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**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE
STATE OF CALIFORNIA**

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	)	Rulemaking 14-08-013 (Filed August 14, 2014)
And Related Matters	)	Application 15-07-002 Application 15-07-003 Application 15-07-006
(NOT CONSOLIDATED)		
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	)	Application 15-07-005 (Filed July 1, 2015)
And Related Matters	)	Application 15-07-007 Application 15-07-008

DEMONSTRATION PROJECTS A & B IMPLEMENTATION PLANS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)

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June 16, 2016

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DEMONSTRATION PROJECTS A & B IMPLEMENTATION PLANS OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)

Pursuant to the *Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B*, dated May 2, 2016 (the "ACR"), and in reliance on the e-mail from Administrative Law Judge Robert M. Mason III to the parties in these proceedings on June 10, 2016, which states that a forthcoming ruling will grant the Joint Motion of San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas & Electric Company, dated June 9, 2016, to modify specific portions of the ACR with respect to Demonstration Project A, San Diego Gas & Electric Company hereby submits, as Attachments 1 and 2, its implementation plans for Demonstration Projects A & B, respectively.

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Respectfully submitted,

/s/ Jonathan J. Newlander

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Attachment 1

SDG&E's Distribution Resource Plan Demonstration A – Dynamic Integration Capacity Analysis (Detailed Implementation Plan)

Executive Summary

This document is a detailed implementation plan "Plan" for SDG&E's Integration Capacity Analysis (ICA) Demonstration A "ICA Demo A" as required per the Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B (May 2nd, 2016) aka "Ruling". This Plan details the project execution including metrics, schedule, and reporting interval. SDG&E's project team will coordinate the implementation of this Plan with the Integration Capacity Analysis (ICA) Working Group as directed in the Ruling to ensure that objectives are being met and adjusted as needed.

As directed in the Ruling, this Plan reflects applicable modifications to SDG&E's proposed ICA methodology, which include, but are not limited to, evaluating the speed vs. accuracy of performing an ICA using a streamlined methodology vs. a dynamic analysis methodology.

Objectives

SDG&E has identified the following eight objectives as being described by the language within the Rulings. The information gained by pursing and achieving these objectives will inform the ICA Working Group's short-term and long-term deliverables as outlined in the Rulings, which include, among other things, a recommendation on improvements and refinements to the ICA methodology used in this Demonstration A that could be adopted in a Q1 2017 ICA Decision.

1. **Study Reverse Flow at T&D Interface**
2. **Diverse Locations**
3. **Incorporate Portfolios and New Technology**
4. **Consistent Maps and Outputs**
5. **Computational Efficiency**
6. **Comparative Analysis**
7. **Locational Load Shapes**
8. **Future Roadmap**

Timeline

The following timeline reflects key milestones to this Plan.

Task	Date Due
Initiate ICA Working Group	12 May 2016
File Revised Demo A Plan	16 June 2016
Meet monthly to monitor and support Demo A	Q2 – Q4 2016
Execute Tasks on Selected Areas	Q3 2016
Status Report to Working Group on Demo A	01 October 2016
Finalize Results and Comparative Analysis	Q4 2016
Final Report on Demo A	Q4 2016

Plan Requirements from the Assigned Commissioner Ruling

This document is a detailed implementation plan for SDG&E's ICA Demo A and includes metrics, schedule, and reporting interval information. As required by the Ruling, this ICA Demo A Plan includes:

a) Documentation of specific and unique project learning objectives for each of the Demonstration A projects, including how the results of the project are used to inform ICA development and improvement;
b) A detailed description of the revised ICA methodology that conforms to the guidance in Section 1.3 and Section 1.4 of the Ruling, including a process flow chart.
c) A description of the load forecasting or load characterization methodology or tool used to prepare the ICA;
d) Schedule/Gantt chart of the ICA development process, showing:
   i) Any external (vendor or contract) work required to support it
   ii) Additional project details and milestones including, deliverables, issues to be tested, and tool configurations to be tested;
e) Any additional resources required to implement ICA Demo A not described in the Applications;
f) A plan for monitoring and reporting intermediate results and a schedule for reporting out.
g) Electronic files shall be made available to the CPUC Energy Division and ORA to view and validate inputs, models, limit criteria, and results. Subject to appropriate confidentiality rules, other parties may also request copies of these files;
h) Any additional information necessary to determine the probability of accurate results and the need for further qualification testing for the wider use of the ICA methodology and to provide the ultimate evaluation of ex-post accuracy.
i) ORA's proposed twelve (12) criteria or metrics of success to evaluate IOU ICA tools, methodologies and results are adopted and should be used as guiding principles for evaluating ICA Demo A Requirements

Demonstration A Learning Objectives

The following eight learning objectives are developed from language within the Rulings, specifically Sections 2 and 3.1 of the Appendix in the May 2, 2016 Ruling. SDG&E will explore and report on these learnings objectives while implementing the project to help inform recommendations to be made by the ICA Working Group to the Commission. The following sections describe these objectives in more detail and also contain a Gantt Chart of key activities.

1.) **Study Reverse Flow at T&D Interface:** DER Capacity with and without limiting reverse power beyond substation busbar. SDG&E also wishes to include discussion or consideration of Transmission hosting capacity limitations where possible in the ICA Working Group. This is important as to not overestimate locational transmission reverse flow capabilities without explicitly analyzing within ICA. If the transmission constraint is lower than the hosting capacity identified in the distribution analysis, the hosting capacity identified in the transmission analysis will become the ICA limit, regardless of backflow.

2.) **Diverse Locations:** Evaluate two DPAs covering broad range of electrical characteristics. SDG&E will analyze its Northeast and Ramona districts, which range from long, rural overhead circuits, to short, urban underground circuits. These districts also have circuits with different load characteristics, from residential to commercial/industrial, to some agricultural load.

3.) **Incorporate Portfolios and New Technology:** Methods for evaluating DER portfolios, CAISO dispatch, Smart Inverters, and other technology. SDG&E will evaluate both the portfolios identified in the Ruling, as well as portfolios agreed upon by the ICA Working Group as important to DER development.

4.) **Consistent Maps and Outputs:** Consistent and readable maps to the public with similar data and visual aspects. SDG&E will work with the other IOUs and the ICA Working Group to develop an interface that is consistent as well as easy to interpret, based on guidance from the working group.

5.) **Computational Efficiency:** Evaluate methods for a faster and more accurate update process that works for entire service territory. Evaluate hardware/software updates needed to expand and support ongoing refresh cycles.

6.) **Comparative Analysis:** Benchmark for consistency and validation across techniques and IOUs. As noted in the comparative analysis section, SDG&E will be running multiple analyses to compare both methodologies on its own system, as well as with the other IOUs for consistency of results.

7.) **Locational Load Shapes:** Utilize Smart Meters for localized load shapes. SDG&E currently leverages its Advanced Metering Instructure (AMI) to develop customer load profiles for use in Synergi – SDG&E's dynamic load flow model.

8.) **Future Roadmap:** Determine roadmap and timelines for future ICA achievements based on demonstration learnings. Through the ICA working group, SDG&E will collaboratively develop recommendations for future ICA improvements.

ICA Baseline Requirements and Conformance

The baseline methodology as described in the Rulings includes 4 steps to evaluating the hosting capacity of a distribution circuit or substation. SDG&E's iterative power flow methodology conforms to these four steps, as described below. SDG&E has contracted a consultant to aid in also performing the ICA using the streamlined method as a means to compare streamlined ICA method results against the iterative power flow method results for accuracy, flexibility, and speed of computation.

Distribution Planning Areas Selected

The Ruling instructs the utilities to apply the ICA as part of Demonstration Project A to two Distribution Planning Areas (DPAs). SDG&E has chosen its Northeast and Ramona districts as the DPAs in which to implement Demonstration Project A. Figure 1 below shows these two DPAs within SDG&E's service territory.

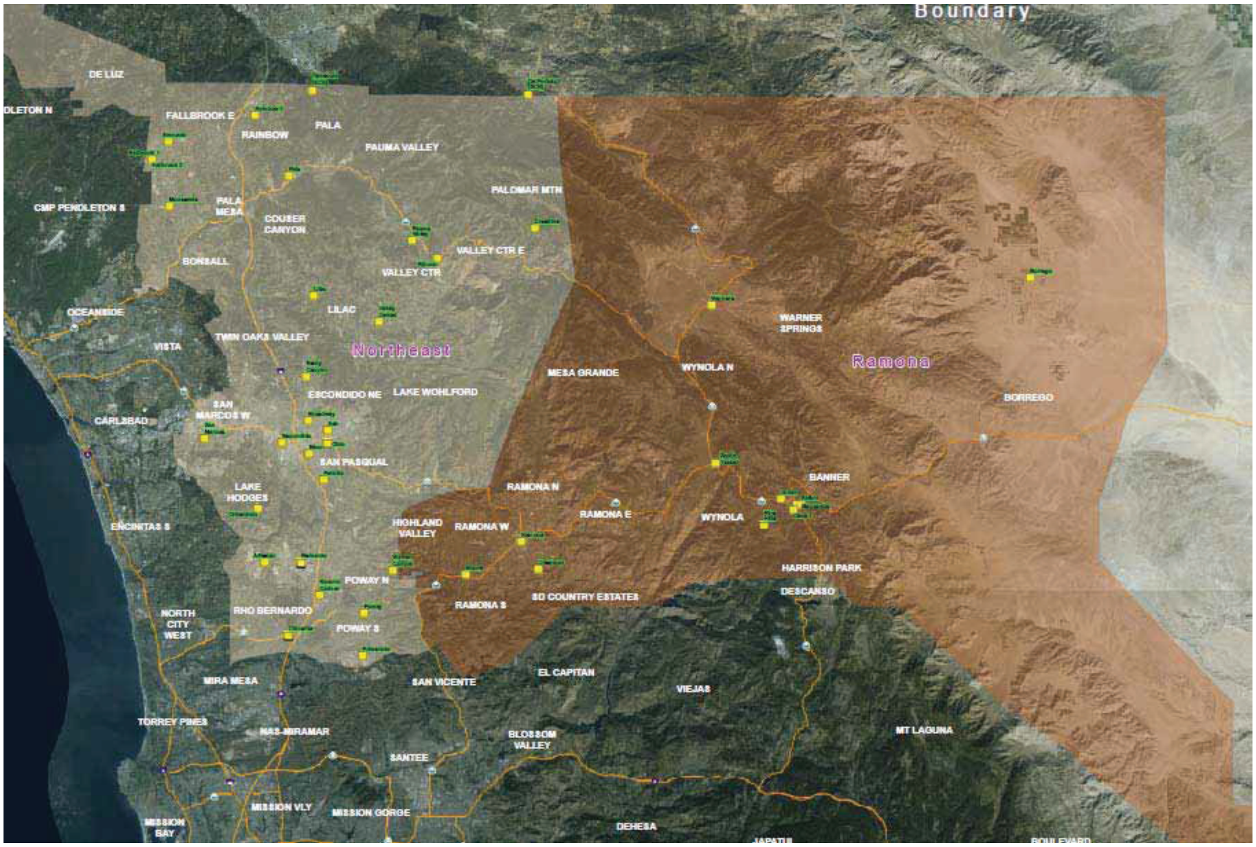

Figure 1. Northeast and Ramona Districts

These two DPAs represent one urban/suburban and one rural DPA within the SDG&E territory. The intent of picking a DPA from each of these categories is to get varying characteristics in which to evaluate varying conditions in the system. The other goal is to drive coordinated learnings with the other demonstration projects. Here is some general information about the DPAs:

Table 1: Northeast and Ramona Statistics

	Northeast	Ramona
Total Customers	210618	20917
Residential	183720	17303
Industrial	120	7
Commercial	26778	3607
Circuits	150	27
Substations	29	11
Transformers	38588	8278

Establish distribution system level of granularity

The first step in performing an ICA is to develop a detailed 12kV distribution circuit model. Synergi imports facilities data from SDG&E's Geographic Information System (GIS). Figure 2 illustrates some of the facility data extracted.

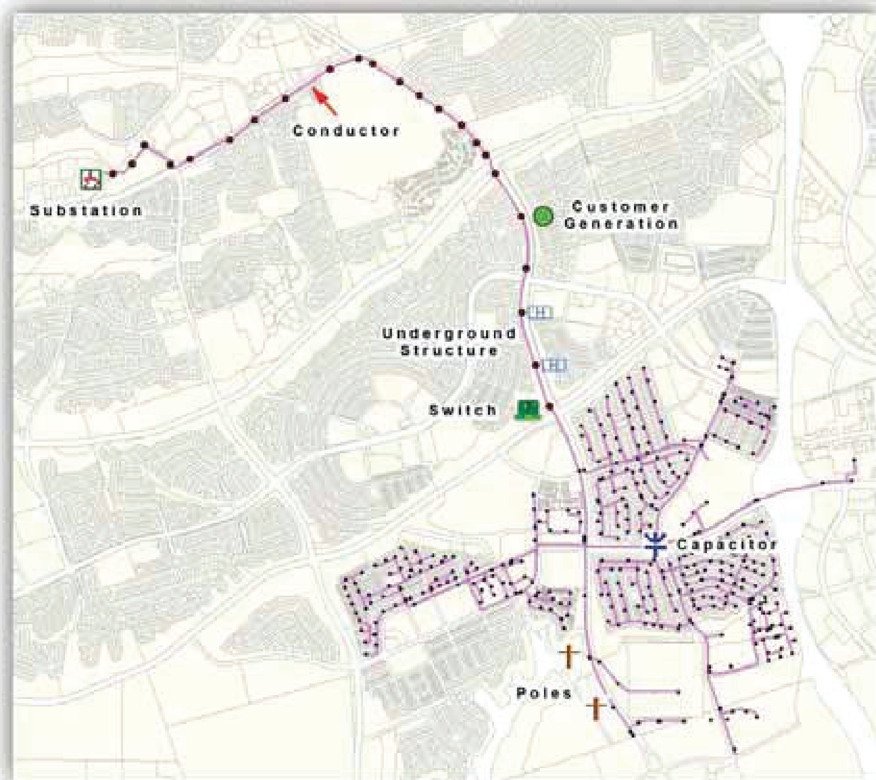

Figure 2. GIS Data Extraction

The extracted data from the GIS includes the material type and length of the conductor, type of switch, structures and subsurface equipment, reclosers, sectionalizers, fuses, capacitors, voltage regulators, generators, connected kVA and type of substation equipment.

Using this level of detailed data allows for a high level of granularity to accomplish an analysis of each line segment. In the GIS model, a line segment represents an electrical path between two points or nodes. A node is defined as a pole or underground structure. The analysis will be applied to all the line segments on the main feeder and branches including three phase and single phase lines. Figure 3 illustrates how the single phase portion of a circuit is identified in the Synergi model

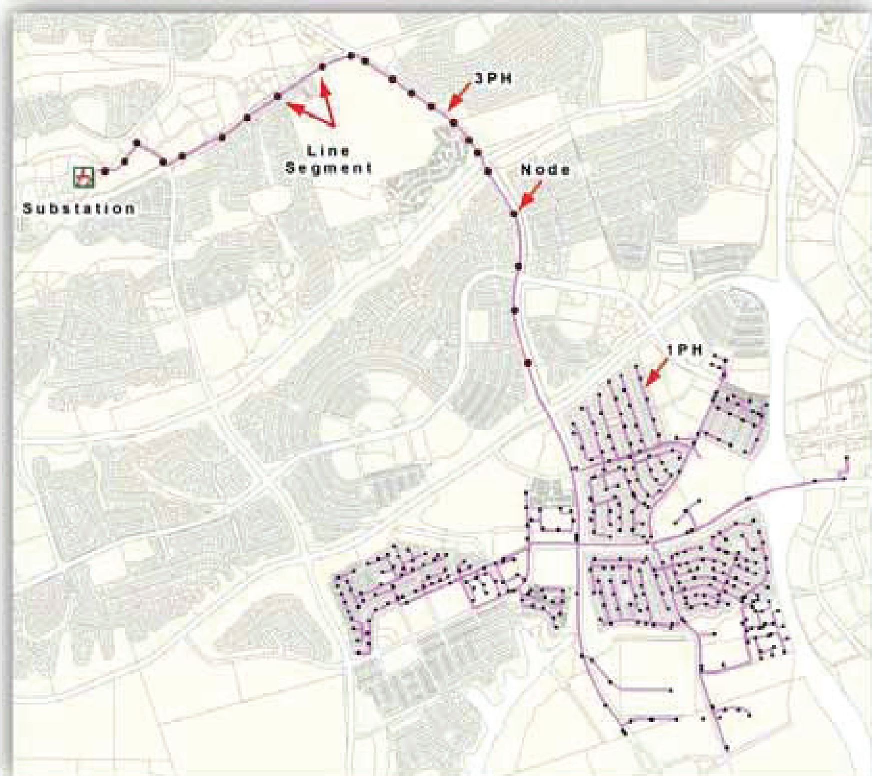

Figure 3. GIS Extraction Including Nodes and Single Phase Lines

Model and extract power system data

SDG&E uses an interactive power flow simulation process to perform the ICA. This approach performs power flow analysis on the circuit model using Synergi. The analysis will be conducted on each line segment up to the substation bus level. Figure 4 illustrates the following informational databases that are used to build the circuit models.

- **GIS:** The circuit model is built from detailed data, as described in level of granularity.

- **Master Data Warehouse**: A database that contains the DER Profiles[1], Load Profiles, and the thermal ratings for the conductors and devices that Synergi will use for analysis.
- **LoadSEER:** A load forecasting model.
- **Supervisory Control And Data Acquisition (SCADA) devices:** SCADA data is leveraged by LoadSEER to develop the demand profile for each circuit, which is then aggregated up to the substation bus level.
- **Customer Information System (CIS):** Customer billing code is acquired to establish customer zones by customer class.
- **Advanced Metering Infrastructure (AMI):** Interval metered load data is recorded for all customers on every circuit and allocated to the circuit model.

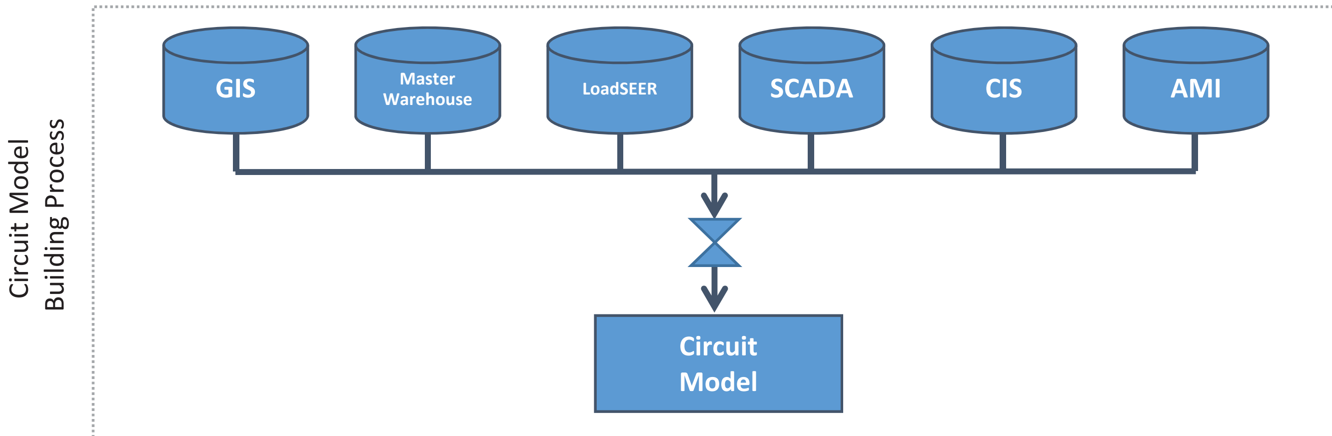

Figure 4. Databases Used to Build Circuit Models for ICA

Once the circuit models are built, AMI data and LoadSEER are used to develop demand curves for each circuit based on customer class and historical data. LoadSEER develops curves from SCADA data, while AMI data is used to allocate the demand data to each service transformer appropriately.

Evaluate power system criteria to determine DER capacity

Synergi and LoadSEER will be used to evaluate power system criteria on the circuit model to determined DER capacity limits on each distribution circuit. As required by the Ruling, four general power system criteria were used in the ICA to determine the hosting capacity for DER. Please see Figure 5 for a flowchart of how the data and criteria are incorporated into the ICA methodology.

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[1] SDG&E is using the DER profiles provided by PG&E

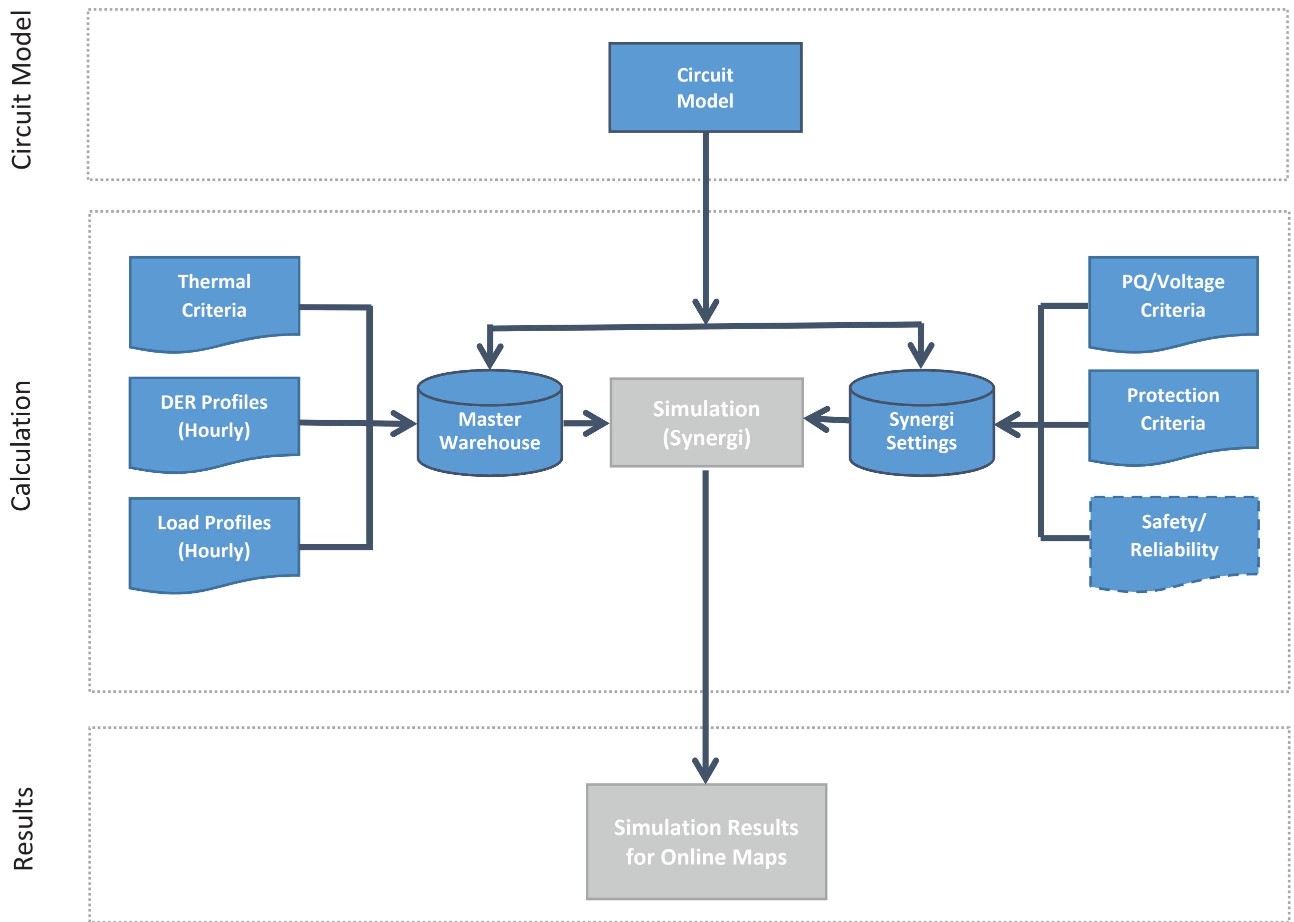

Figure 5. ICA Methodology Flowchart

The Ruling instructs the utilities, as part of Demonstration Project A, to incorporate the list of analyses from PG&E's table 2-4 in its DRP filing to the extent feasible. SDG&E has modified the table to provide the detailed criteria that will be evaluated as part of Demonstration Project A, and what remains as potential future analysis to be evaluated. This modified table is included as Table 2 below.

Table 2. Power System Criteria Analyzed in SDG&E's Demonstration A Project

POWER SYSTEM CRITEIA TO EVALUATE CAPACITY LIMITS		
POWER SYSTEM CRITERIA	**Demonstration A Analysis**	**Potential Future Analysis**
Thermal		
Substation Transformer	X	X
Circuit Breaker	X	X
Primary Conductor	X	X
Main Line Device	X	X
Tap Line device	X	X
Service Transformer		X
Secondary Conductor		X
Transmission Line		X
Voltage/Power Quality		
Transient Voltage	X	X
Steady State Voltage	X	X
Voltage Regulator Impact		X
Substation Load tap Changer Impact		X
Harmonic Resonance/ Distortion		X
Transmission Voltage Impact		X
Protection		
Line Equipment Interrupter Capability	X	X
Protective Relay Reduction of Reach	X	X
Fuse Coordination		X
Sympathetic Tripping		X
Transmission Protection		X
Safety/Reliability		
Islanding		X
Transmission Penetration	X	X
Operational Flexibility	X	X
Transmission System Frequency		X
Transmission System Recovery		X

Thermal Criteria

Thermal Criteria determines whether the addition of DER to the circuit causes equipment thermal ratings to be exceeded. Thermal limits shall be the rated capacity of the conductor, transformer, cable and line devices established from SDG&E Engineering Standards or equipment manufacturers. The Integration Capacity value is the highest DER value that does not exceed the thermal rating of any equipment on the distribution circuit or substation.

Voltage/Power Quality

Voltage/Power Quality criteria ensure that customer facilities and equipment are not damaged by operating outside of allowable power quality and voltage limits. There are both steady state voltage limits and voltage fluctuation limits established by SDG&E's Rule 2 and SDG&E's Engineering Standards, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A.

Protection Criteria

Protection criteria are used to determine if the DER causes problems with the existing protection schemes on the circuits that protect and isolate during system events. The protection limit is based both on a check on the feeder breaker, switch, and recloser fault current interrupter rating by adding the DER fault contribution to the existing fault current to verify that equipment interrupter ratings are not exceeded, and a breaker reach critierion.

Safety/Reliability Criteria

As a minimum to operate on SDG&E's distribution system, all DER equipment must meet the certified anti-islanding requirements of UL1741 and ANSI/IEEE 1547. High penetration scenarios of DER can have the potential to cause reverse flow that can affect reliability during system events. Operation flexibility limits are a concern with high penetration DER and the impact to abnormal distribution system conditions, circuit transfers and emergency restoration.

Calculate ICA results and display on online map

ICA calculations will be performed using the interactive simulation process. Each criteria limit is calculated for the most limiting value and is used to establish the integration capacity (IC) limit. The resulting IC data will be publicly available using the Renewable Auction Mechanism (RAM) Program Map. The ICA maps will be available online and will provide a user with access to the results of the ICA by clicking on the map. The map will be characterized as a "Heat Map" colored by range of generation as agreed upon by the IOUs and ICA Working Group. Figure 6 shows and example of what a heat map might look like.

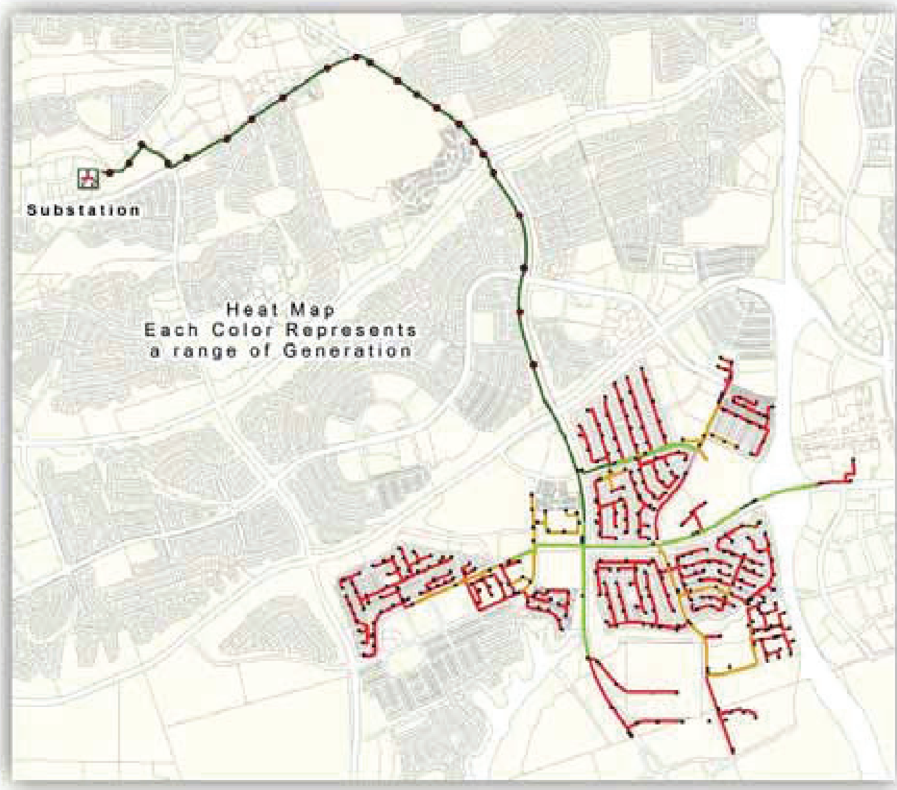

Figure 6. Heat Map Example

The line segment will provide capacity for the following DER types as required by the Ruling:

- EV – Residential (EV Rate)
- EV – Residential (TOU Rate)
- EV – Workplace
- PV
- PV with Storage
- PV with Tracker
- Storage – Peak Shaving
- Uniform Generation (Inverter)
- Uniform Generation (Machine)
- Uniform Load

The capacity limit will be displayed on the RAM maps by clicking on the line segment. The call out box will display the available capacity limit at the line segment, feeder and substation bus. For illustrative purposes, Figure 7 shows a dialogue box similar to that used in PG&E's ICA maps. The IOUs along with the ICA Working Group will decide on a common display for ease of understanding.

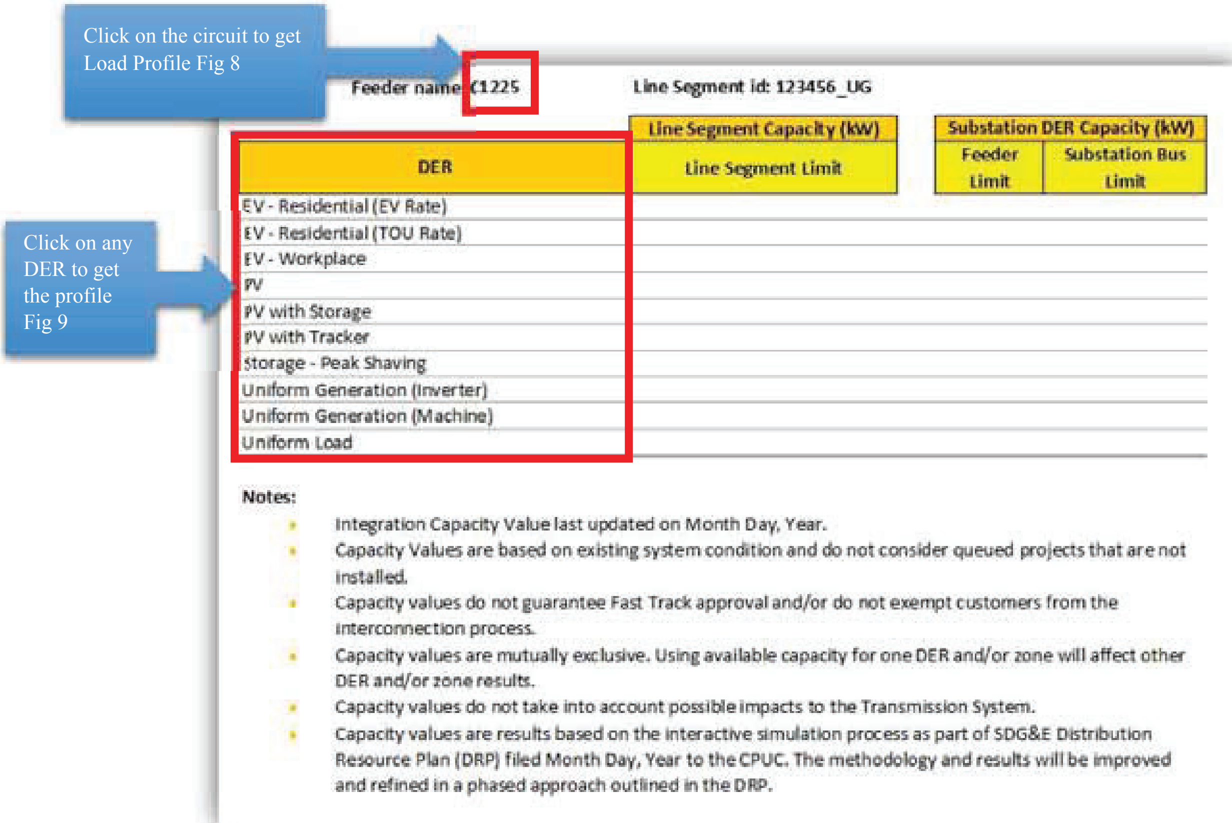

Figure 7. Dialogue Box Example

The hourly Load Profile and distribution of Customer Class by circuit will be displayed on the RAM maps by clicking on the Feeder, a call out box will display the load profile (MW) and customer load percent at the feeder level, that can be downloaded as an XML, CVS, or similar file. Figure 8 shows an example of what the load profile will look like on the ICA maps. SDG&E expects that through the ICA working group process, improvements and refinements to the ICA maps will be developed, including such items as heat map displays (colors, parameters, etc.), downloadable file formats, and dialogue displays.

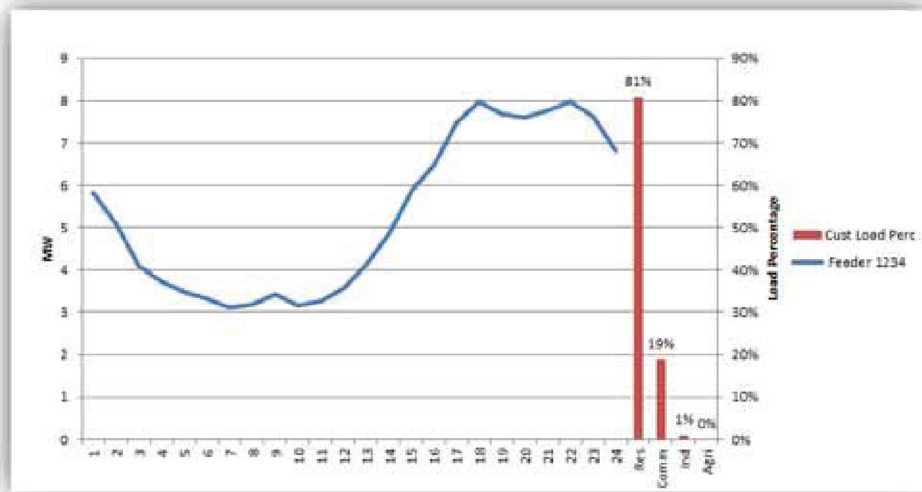

Figure 8. Load Profile Example

The 10 different DER Profiles will be available to be displayed by clicking on each individual type of DER on the call out box (Figure 7). Each profile will be displayed in a graph shape, that can be downloaded as an XML or CVS file. Figure 9 shows sample of all 10 profiles.

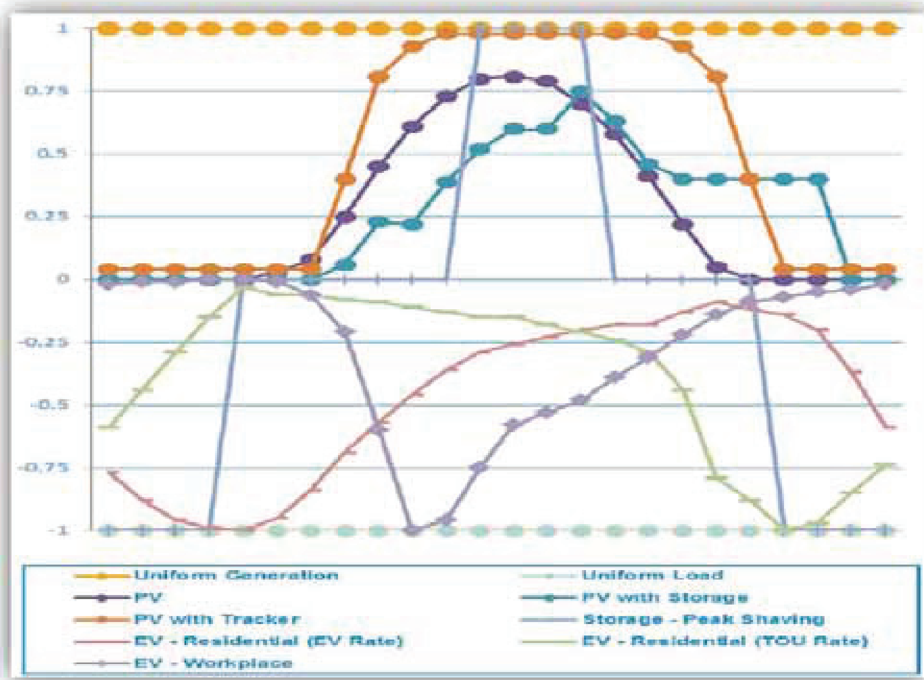

Figure 9. DER Profiles

In addition to updated appearance, the maps will have increased data available for viewers to download and analyze. This data will be in the form of downloadable files that can be used in standard spreadsheet software programs. SDG&E will also coordinate with the other IOUs to develop similar displays, as much as feasible within GIS platform restrictions.

Tools Used to Prepare ICA

SDG&E's ICA uses a suite of tools to perform the analysis, from power flow to load forecasting. Below is a description of these tools and how they will be utilized in the demonstration A project.

Power Flow Analysis

The ICA methodology SDG&E intends to implement will include running powerflow analysis that will account for all reactive devices on each distribution circuit and substation bus. Currently SDG&E already runs powerflow analysis for each of its distribution circuits within the Synergi software program and models all distribution capacitors with control settings/logic for the devices that are consistent with settings that are being used by the devices in the field. The settings are verified through a yearly capacitor survey in which the settings for each unit are confirmed and recorded. As a part of developing the ICA, SDG&E is already in the process of working with the vendor of Synergi (DNVGL) to properly model substation transformer banks w/ LTC's, substation buses, and substation capacitors. This will ensure SDG&E has proper visibility of DER impact at the substation level and can optimize substation equipment to potentially allow for greater DER penetration without negatively impacting any customers downstream.

Ultimately this effort will result in SDG&E being able to run a more comprehensive powerflow analysis that includes the complete substation bus with all connected feeders downstream so the analysis can account for DERs impact on adjacent feeders.

Load Forecasting

As a part of the ICA SDG&E has and will continue to refine its distribution load forecasting to include the impacts of future DERs on load growth. SDG&E has already modified its load forecasts to account for the present day reduction in load due to existing DER's by modifying load profiles to include all downstream DER generation output coincident with the load on each circuit. SDG&E is also incorporating the growth scenarios from the DRP to include DER deployment forecasts in order to appropriately modify future forecasted load profiles. For the purposes of Demonstration Project A, ICA values are based on SDG&E's existing forecasts, modified for the presence of existing DERs. SDG&E will work to develop or use third party DER forecasts that have a high degree of certainty in order to insure that capacity and reliability issues do not arise as a result of over/under optimistic DER forecasts.

SDG&E plans to utilize LoadSEER to develop its forecasted load shapes that are uploaded to Synergi for the ICA. LoadSEER will allow SDG&E to progress from the existing point-in-time forecast to an hourly demand-curve type forecast. The advancement enables SDG&E to perform power flow analysis against multiple DER profiles throughout the day. This tool employs multiple statistical methods including SCADA as well as weather data throughout the SDG&E service territory to derive statistical modeling of peak load history, econometric modeling of energy, and a GIS-based land use simulation analysis (spatial forecasting), all of which are used to develop forecasted load shapes. LoadSEER assigns CEC system level mid case demand to the appropriate substations as well as circuit to establish the growth by utilizing the statistical methods described previously. The two DER growth scenarios (scenario I and scenario III) established by SDG&E with the IEPR forecast mid-energy demand case as the base will also be included in the forecasted load shapes. The final product will be a typical high load forecasted load shape day and a typical low load forecasted load shape day for each month for the next 10 years. A detailed description of LoadSEER is available within SDG&E filed DRP.

Streamlined Analysis

SDG&E, through the use of a third party consultant, will be performing a streamlined analysis as part of Demonstration Project A. The streamlined analysis will utilize Synergi to extract data from the power flow model, and LoadSEER to develop the load curves. The streamlined analysis will utilize the modified baseline methodology as described in the Ruling, determining limits based on the same four criteria as the iterative power flow method. Instead of performing an iterative power flow simulation, the streamlined analysis will perform a baseline power flow, then extract the data to be analyzed in a database. Each node will be tested using the criteria equations, and the limit for each criterion reported out.

Schedule/Gantt Chart

The schedule for SDG&E's Demonstration Project A is shown in Figure 10 below.

ID	Task Mode	Task Name	Duration	Start	Finish
1		**Reverse power flow at T&D interface**	**142 days**	**Fri 6/17/16**	**Sat 12/31/16**
2		**Develop Bus flows**	**71 days**	**Fri 6/17/16**	**Fri 9/23/16**
3		develop substation models	12 days	Fri 6/17/16	Mon 7/4/16
4		Develop load profiles	12 days	Fri 6/17/16	Mon 7/4/16
5		Perform ICA	60 days	Mon 7/4/16	Fri 9/23/16
6		Determine trans impacts	88 days	Thu 9/1/16	Sat 12/31/16
7		Select DPAs	55 days	Mon 4/4/16	Fri 6/17/16
8		Develop DER profiles	80 days	Mon 5/2/16	Fri 8/19/16
9		**Develop DER portfolios**	**142 days**	**Fri 6/17/16**	**Sat 12/31/16**
10		Develop base portfolios	55 days	Fri 6/17/16	Thu 9/1/16
11		ICA WG Portfolio Meeting	1 day	Wed 8/10/16	Wed 8/10/16
12		develop WG portfolios	88 days	Thu 9/1/16	Sat 12/31/16
13		**Update ICA maps**	**196 days**	**Mon 4/4/16**	**Sat 12/31/16**
14		ICA WG Map meeting	1 day	Tue 7/19/16	Tue 7/19/16
15		Determine new fields	86 days	Mon 4/4/16	Sun 7/31/16
16		Modify maps	111 days	Mon 8/1/16	Sat 12/31/16
17		**Comparative Analysis**	**45 days**	**Tue 11/1/16**	**Sat 12/31/16**
18		ICA WG Meeting	1 day	Tue 11/15/16	Tue 11/15/16
19		Future Roadmap	45 days	Tue 11/1/16	Sat 12/31/16
20		Final Demonstration A report	0 days	Fri 12/30/16	Fri 12/30/16

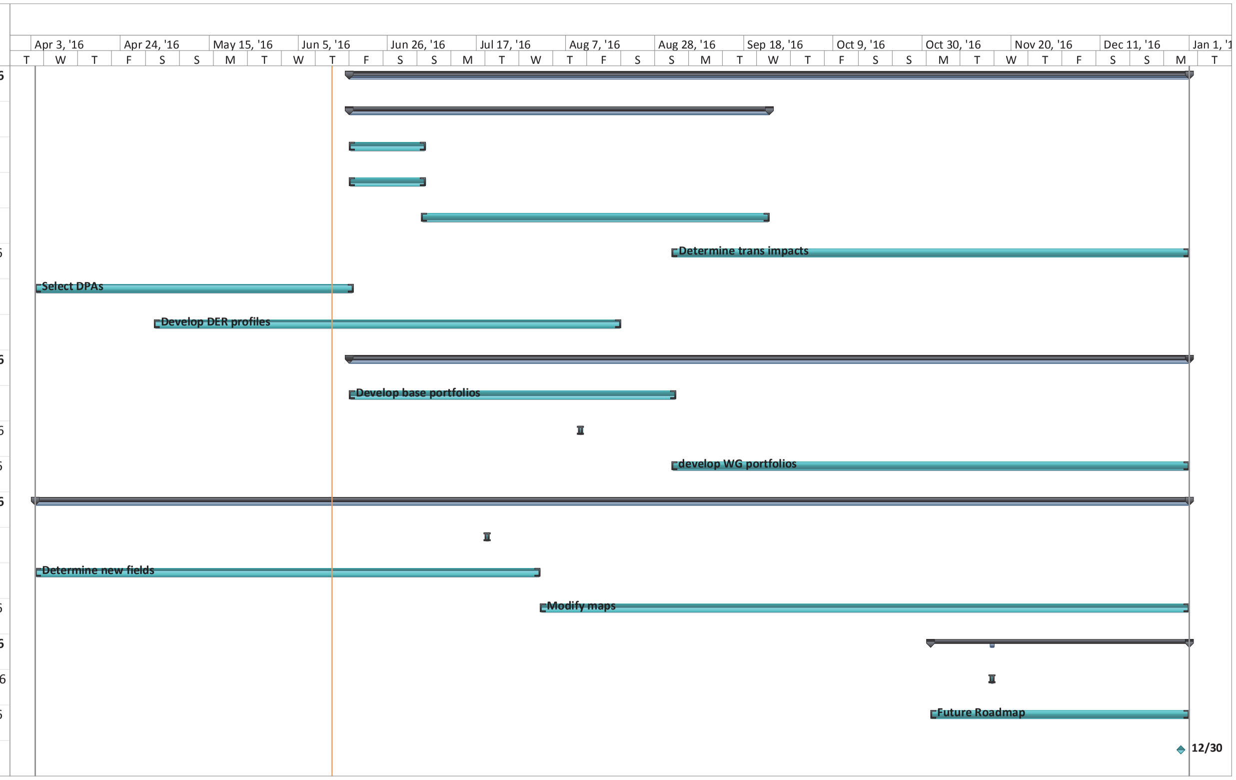

Figure 10. Demonstration Project A Schedule

Additional Resources

SDG&E is utilizing additional resources in various areas as part of demonstration A. SDG&E is working with its power flow software vendor to modify the software to perform many of the analyses required by the Ruling for demonstration A using the iterative power flow method. SDG&E is also working with a consultant to perform the ICA using the streamlined method. Additionally, SDG&E will be leveraging the services of an outside vendor to modify its GIS platform to enable the mapping functions required by the Ruling. SDG&E may also work with outside vendors to develop plans to scale its hardware and software computing capabilities. If hardware and software upgrades are required, SDG&E expects that significant investments will be required to implement these upgrades.

Monitoring, Reporting Progress and Results

SDG&E believes that the ICA working group will provide valuable insight into the needs of DER providers and usefulness of ICA results. SDG&E will report out to the ICA working group monthly on the progress of the ICA, including both streamlined and iterative analyses, map development, and comparative analysis. Reports will be developed with the input from the ICA working group regarding format and content.

Availability of Project Files

SDG&E intends to make available as part of its ICA maps the results in a downloadable format such as CSV and XML. In addition to the results, data such as DER profiles and load profiles used in the analysis will be available. The data will be downloadable via a hyperlink from the ICA maps.

Comparative Evaluation and Benchmarking

The three IOUs have strived to align their respective ICA methodologies to evaluate the same power system criteria. SDG&E's power flow methodology performs an iterative power flow analysis on every line segment in its distribution system, and reports out any criteria violations similar to the baseline methodology. Figure 11 below is a process diagram that shows the steps that SDG&E's methodology goes through to determine the IC on each line segment, feeder, and transformer bank. This process closely aligns with the baseline methodology as described by ORA[2].

[2] As described in the ICA workshop presentation "Evaluation of Utility Integration Capacity Analysis (ICAs)", p8

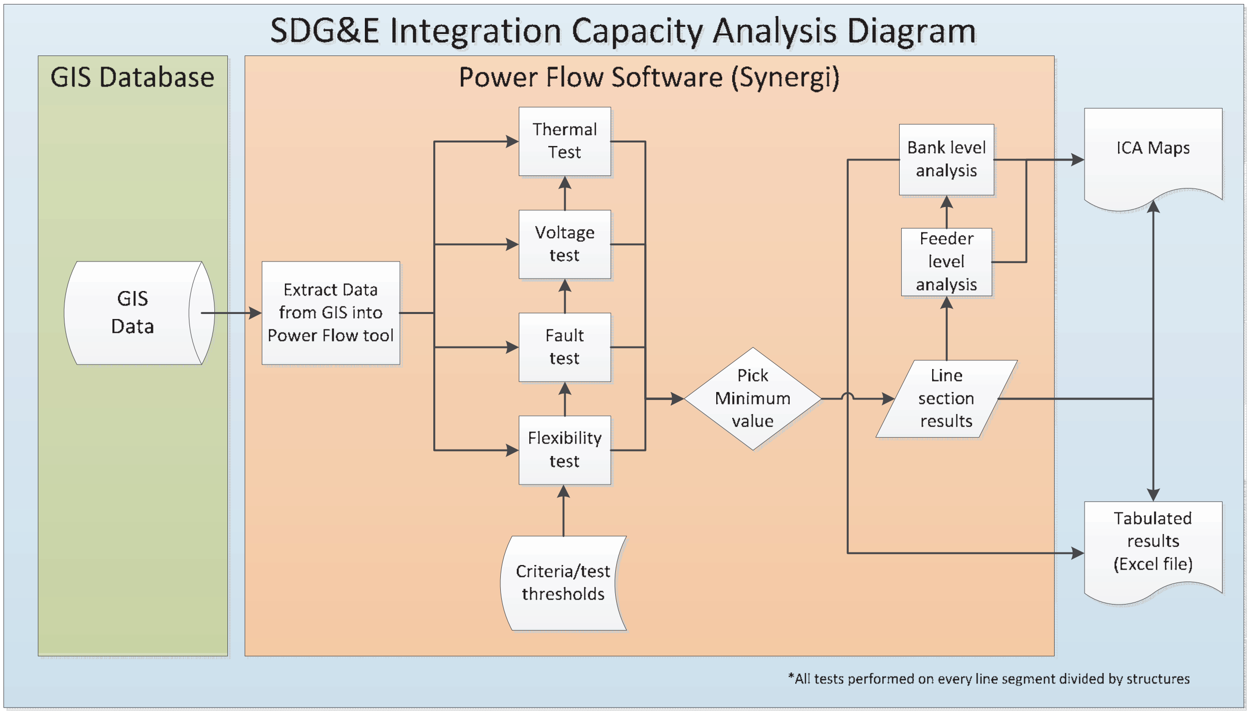

Figure 11. SDG&E's ICA Process

As can be seen in the diagram, the processes and criteria checks are the same as the baseline. SDG&E's iterative power flow analysis performs these tests within the power flow software itself, vs extracting the data and utilizing a SQL database to perform these calculations.

In order to verify consistency among the IOUs, each will apply their respective methodologies to representative test circuits. These circuits were chosen based on electrical characteristics, load profile, DER penetration, and customer composition to achieve a representative sample of circuits that will fairly test the methodologies. The full complement of ICA criteria will be tested on each circuit so that the full scope of the ICA for each IOU is tested.

The ICA Working Group issued a request that each IOU lay out a detailed protocol explaining how results of the individual IOU Demo A projects will be analyzed to allow comparison of: a) ICA accuracy; b) ICA consistency; c) incremental ICA computing needs and costs; d) ICA computing time. SDG&E describes its comparison methods below.

ICA Accuracy

For the ICA to truly impact the interconnection process, the methodology needs to produce an accurate result. To ensure accuracy, each test circuit will be tested using the streamlined methodology and the iterative power flow method, both batch run as part of the ICA, and a manual check using the power flow software interactively. The manual check will provide the basis for accuracy, as this is how a typical interconnection study would be performed outside of the ICA. Due to the time constraints of manual power flow, the manual check will only be performed for a random selection of nodes throughout the feeder. If the results of either the ICA power flow or streamlined ICA method match the results of the manual power flow, the results will be deemed accurate. Below is an example of how the circuit results might be compared.

Table 3. ICA Method Comparison Example

	ICA Power Flow Method		Streamlined Method		Manual Power Flow	
Test Circuit	ICA Limit (MW)	Criteria Limit	ICA Limit (MW)	Criteria Limit	ICA Limit (MW)	Criteria Limit
Circuit A	2.4	Voltage	2.6	Voltage	2.4	Voltage
Circuit B	5.2	Thermal	5.1	Thermal	5.2	Thermal
Circuit C	3.7	Protection	4.1	Protection	3.7	Protection

ICA Consistency

For the DER community to fully leverage the ICA maps of all three IOUs, the results of each ICA must be consistent among all three IOUs. Again, SDG&E and the other IOUs will leverage the use of test circuits to perform the ICA and benchmark against each other. Each IOU will perform the two ICA methods on the test circuits, and report out results so that they may be compared. Table 4 below shows how the results might be compared for the streamlined method.

Table 4. IOU Results Comparison Example

Streamlined Method						
	SCE		PG&E		SDG&E	
Test Circuit	ICA Limit (MW)	Criteria Limit	ICA Limit (MW)	Criteria Limit	ICA Limit (MW)	Criteria Limit
Circuit A	2.4	Voltage	2.6	Voltage	2.4	Voltage
Circuit B	5.2	Thermal	5.2	Thermal	5.2	Thermal
Circuit C	3.7	Protection	4.1	Protection	3.9	Protection

Incremental ICA Computing Needs

There has been concern within the ICA Working Group that the addition of scenario and portfolio analysis will increase the IT resources (both hardware and software) required to perform the batch ICA beyond the present capabilities of the IOUs. SDG&E will evaluate the computing time of both the iterative power flow method and the streamlined method to determine if additional or alternative computing infrastructure is required to perform scenario analysis as well as support ongoing ICA refreshes.

ICA Computing Time

As part of Demonstration Project A, SDG&E will analyze the computing time of both its iterative power flow method and the streamlined method. SDG&E will develop a time per circuit metric, identifying the processing time as well as hardware requirements so that the results can be compared across the utilities. However, it should be noted that all three IOUs IT systems are different and therefore will provide inherently different computation times.

SDG&E has already undertaken efforts with its power flow software vendor to decrease the computing time of the ICA by performing the analysis within the user interface of the software, rather than as a function call from outside the software.

Success Metrics for ICA Evaluation

The Ruling required the IOUs to incorporate ORA's recommended 12 success metrics in the November 10th 2015 ICA workshop. SDG&E believes that its methodology meets or exceeds each of these metrics as described below.

Accurate and meaningful results

a. Meaningful scenarios
   SDG&E will evaluate the distribution system to determine the impacts of DER on the distribution system for various DER technologies and portfolios, providing a broad array of results that can be used by the DER community to evaluate project feasibility.

b. Reasonable technology assumptions
   SDG&E will leverage its experience in deploying energy storage, PV solar, and other technologies to develop assumptions around the various technologies and their performance characteristics. For new technologies, SDG&E will work with vendors and DER developers to determine appropriate characteristics.

c. Accurate inputs (i.e. load and DER profiles)
   As described previously, SDG&E will be leveraging LoadSEER and SCADA data to develop load profiles, and will use industry and proprietary data to develop

DER profiles (e.g., meteorological data to develop PV curves). These tools will provide accurate inputs into SDG&E's ICA.

d. Reasonable tests (i.e. voltage flicker)
As described above, SDG&E utilizes industry standard tests to determine the hosting capacity of the power system. These tests are the same that SDG&E uses in distribution planning year after year to ensure the safety and reliability of the distribution system.

e. Reasonable test criteria (i.e. 3% flicker allowed)
As described above, SDG&E utilizes industry standard criteria to determine the hosting capacity of the power system. These criteria are the same that SDG&E uses in distribution planning year after year to ensure the safety and reliability of the distribution system

f. Tests and analysis performed consistently using proven tools, or vetted methodology
SDG&E uses Synergi electric, one of several industry standard tools used to perform power flow analysis on the distribution system.

g. Meaningful result metrics provided in useful formats
SDG&E will provide results in both a map and table form, in downloadable files that DER developers can then query to determine optimal locations.

Transparent methodology

SDG&E's methodology utilizes an industry standard power flow software suite (Synergi) to perform power flow analysis on the distribution system. The ICA is determined by four criteria that comply with industry norms and standards.

Uniform process that is consistently applied

Per the flow chart in Figure 11, SDG&E's methodology is consistent with the baseline methodology. Each of the criteria analyzed is consistent among the IOUs, as well as consistent with industry norms and standards.

Complete coverage of service territory

SDG&E will initially implement the ICA across its Northeastern and Ramona districts as part of demonstration A. SDG&E will report back to the Commission what it will take to complete coverage of its entire service territory.

Useful formats for results

SDG&E will publish the ICA results via online maps, as well as include downloadable data files that can be searched via standard spreadsheet software. This will allow DER developers both visual representation, as well as a file that can be searched and manipulated to find optimal locations on the distribution system.

Consistent with industry, state, and federal standards

The power system criteria used in SDG&E's ICA adheres to industry as well as state and federal standards. Thermal criteria are based on equipment ratings established by manufacturers and design criteria established in CPUC General Orders 95 and 128. Steady state voltage criteria is determined by SDG&E's Rule 2, which are drawn from American National Standard (ANSI) C84.1 - 2011 Range A. Both protection and operational criteria are based on the EPRI hosting capacity methodology.

Accommodates portfolios of DER on one feeder

SDG&E's ICA for demonstration A will analyze portfolios included in the Ruling, as well as portfolios identified by the ICA working group.

Reasonable resolution (a) spatial, (b) temporal

SDG&E's spatial resolution is finer than that required by the baseline methodology outlined in the Ruling. SDG&E intends to use an hourly time series analysis in Demonstration Project A, aligning with the requirements of the Ruling.

Easy to update based on improved and approved changes in methodology

SDG&E has been steadily improving its ICA methodology since the DRP plan filing in 2015. Changes such as single phase analysis have been added to its power flow software since the filing. SDG&E believes that further improvements can be made to the analysis and incorporated into its power flow based analysis. If further hardware and software upgrades are required, SDG&E expects that significant investments will be required to implement these upgrades.

Easy to update based on changes in inputs (loads, DER portfolio, DER penetration, circuit changes, assumptions, etc.)

SDG&E has been steadily improving its ICA methodology since the DRP plan filing in 2015. Changes such as single phase analysis have been added to its power flow software since the filing. SDG&E believes that further improvements can be made to the analysis and incorporated into its power flow based analysis. If further hardware and software upgrades are required, SDG&E expects that significant investments will be required to implement these upgrades.

Consistent methodologies across large IOUs

Per the flow chart in Figure 11, SDG&E's methodology is consistent with the baseline methodology. Each of the criteria analyzed is consistent among the IOUs, as well as consistent with industry norms and standards.

Methodology accommodates variations in local distribution system, such that case by case or distribution planning area (DPA) specific modifications are not needed

SDG&E's methodology is able to be applied system wide, as it relies on fundamental circuit analysis, so that no changes to the methodology are needed to accommodate differences throughout the distribution system.

Conclusion

SDG&E's plan for Demonstration Project A includes all the requirements as laid out in the Ruling refining the ICA and LNBA methodologies. This plan includes the learning objectives, DPA selection, ICA methodology and input descriptions, schedule, and comparison methodology to be used in Demonstration Project A. By applying a rigorous set of success metrics and incorporating valuable input from the ICA Working Group, SDG&E's Demonstration Project A will illustrate the accuracy and validity of iterative power flow analysis to perform the ICA. The lessons learned through Demonstration Project A will inform the ICA Working Group recommendations as well as a Commission decision on the future of ICA methodology.

Attachment 2

Distribution Resources Plan Demonstration B Locational Net Benefits Analysis Implementation Plan

I. Executive Summary

Assembly Bill 327 of 2014 added section 769(b) to the California Public Utilities Code, required each CA IOU to submit a distribution resources plan proposal "to identify optimal locations for the deployment of distributed resources…" using an evaluation of "locational benefits and costs of distributed resources located on the distribution system" based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation. On August 14, 2014, the California's Public Utility Commission ("Commission") issued Rulemaking (R.) 14-08-013 which established guidelines, rules, and procedures to direct California investor-owned electric utilities ("IOUs") to develop their Distribution Resources Plan ("DRP"). In a February 6, 2015 Assigned Commissioner Ruling (ACR), the Commission released guidance[1] for the public utilities in filing their DRP, including requirements for an "optimal location benefit analysis" and demonstration projects, including this one.[2] The locational net benefits methodology/analysis ("LNBA") will help specify the benefit that DERs can provide in a given location, particularly benefits associated with meeting a specific distribution need. Following the filing of the three IOUs' DRPs and workshops on LNBA, an assigned commissioner ruling (ACR) filed May 2, 2016 provided additional guidance to the three IOUs on further development of the LNBA in its application to Demonstration Project B ("Demo B"), a DRP-specified pilot to apply the LNBA.[3]

The objectives of Demo B include:

- Satisfy commission requirements for LNBA and identification of optimal locations

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[1] "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," February 6, 2015.
[2] "Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning," February 6, 2015, Attachment A, pg. 4-6.
[3] "Assigned Commissioner's Ruling (1) Refining Integration Capacity and Locational Net Benefit Analysis Methodologies and Requirements; and (2) Authorizing Demonstration Projects A and B," May 2, 2016.

- Demonstrate locational variability of DERs' T&D net benefits within the DPA(s) in contrast to current system-level approaches
- Develop DER requirements to provide those T&D benefits
- Provide a transparent test of LNBA methods and compile lessons learned for future work

This Implementation Plan provides a more detailed description of how SDG&E intends to fulfill the Commission's requirements for Demo B and achieve the objectives above. Please note, the following methodologies have been jointly developed by the IOUs and E3 except for the specific sections on load forecasting/characterization and DPA selection.

II. Demonstration B Requirements per ACR

Area selection and upgrade projects:

The May, 2016 ACR refined the Integrating Capacity (ICA) and Locational Net Benefits Analysts (LNBA) methodology requirements for the demonstration projects. The ruling affirmed the requirement of the February, 2015 final guidance to evaluate two traditional utility projects, one near term (0- 3 year lead time) and one longer term (3 or more year lead time) project.

The ACR also expanded the scope to require at least one distribution voltage support/power quality- or reliability/resiliency in addition to at least one traditional distribution capacity related deferral opportunity. Selecting two or more DPAs was required if both types of projects (capacity and voltage/reliability) were not located in the same DPA.

Methodology

The Commission guidance on calculating LNBs provides detailed requirements for the T&D components and refers to the DERAC values for other system-level components, such as generation capacity and energy.

The detailed guidance on T&D requires SDG&E to identify and provide detailed information on all upgrade projects and associated services within the selected DPA(s). Where DERs can provide those services, a deferral value will be calculated using the Real Economic Carrying Charge (RECC) method. These steps are required to be performed using two different DER growth scenarios.

At this time, the LNBA does not include DER costs or DER integration/interconnection costs.

Demo B Final Deliverables

The final deliverables of Demo B will include:

1. Demo B Final Report
    1. Description of all projects identified in the selected DPA(s) under two DER growth scenarios,

    2. DER specifications and requirements for deferrable upgrades or expenses calculated using public inputs
    3. Locational net benefits results for all locations in the selected DPA(s)
    4. Locational net benefits final methodology
    5. Lessons learned and recommendations for refining and expanding LNBA
2. Commission-required outputs in machine-readable and map-based format layered over the online ICA map
    1. LNBA results heatmap
    2. DER growth heatmap
    3. Descriptions for all projects and associated services and DER requirements in selected DPA(s)

III. Description of Demo B Process

Summary of Demo B Process

The activities that SDG&E will undertake in Demo B are categorized into four phases:

1. Planning Area Selection
2. Identify and Describe Distribution Upgrade Projects in Selected Planning Area
3. Calculation of Locational Net Benefits
4. Visualization of Information

Phase 1: Planning Area Selection

SDG&E has identified and presented to the LNBA Working Group (WG), proposed DPAs for Demo B. In addition to the Commission requirements summarized earlier, SDG&E has proposed DPAs for Demo B that will also be the focus of Demo A – the Integration Capacity Analysis demonstration project. SDG&E' proposed DPAs represent a broad cross section of types of customers, weather, geography and level of development.

SDG&E proposes that the DPA selections be finalized at the LNBA WG meeting subsequent to the filing of this Implementation Plan. Previously provided DPA information is included here in **Appendix B**.

Phase 2: Identify and Describe Distribution Upgrade Projects in Selected Planning Area

This section outlines the LNBA specific analysis method in terms of identifying full range of applicable electric services and quantifying Distributed Energy Resource (DER) capabilities to provide such services in place of upgrade projects.

A five-step approach is suggested for this work as shown in Figure 1, which addresses the entire process of project selection, project cost estimation, service qualification and cost calculations for the qualified services. These steps will be undertaken for the two required DER growth scenarios.

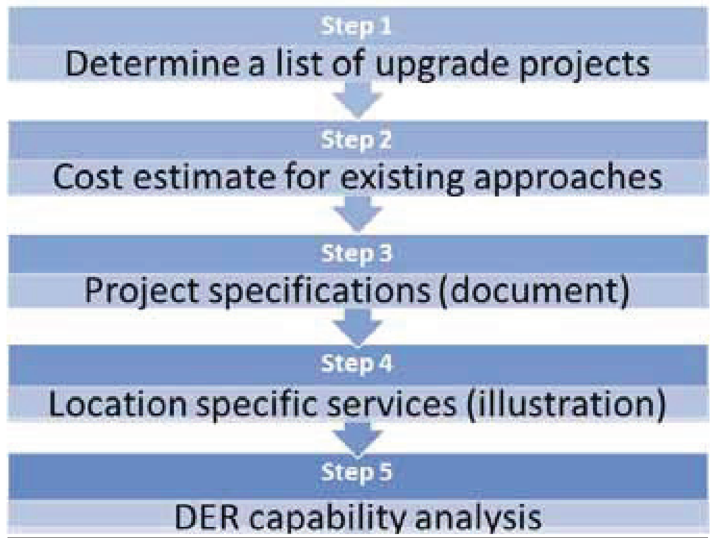


Figure 1 - Project identification and service qualifications

Each IOU has an iterative distribution planning process which identifies needed work using information about installed equipment, its performance and forecasts of future conditions that this installed equipment could experience. Recognizing the importance of this forecast of future conditions, the May, 2016 ACR requested each IOU include a description of its load forecasting methodology in this implementation plan. This description is included as **Appendix A.**

Per the May 2016 ACR, SDG&E will modify its standard planning forecast to incorporate DER growth scenarios 1 and 3 from the July 1, 2015 DRPs, respectively these scenarios represent the IEPR trajectory case and the very high DER growth scenario. The base case will use scenario 1 and a sensitivity analysis will re-evaluate steps 1-5 with the very high DER growth scenario.

Step 1: Determine a List of Upgrade Projects:[4]

Given the future work identified in each IOU's distribution planning process under these modified forecasts, the first step of Demo B is to identify the full range of upgrade projects and associated electric services in the Demo B DPA(s). The service coverage will account for all locations within DPAs selected for the analysis. The list will include any and all electrical services that can be identified through investigation of processes involving determination and planning for distribution grid upgrade projects in three categories of:

- Utility distribution planning processes
- Circuit reliability/resiliency improvement processes
- Maintenance processes

[4] See section 4.4.1(A) and (B) and 5.1 of the May 2016 ACR

To assess the value of a service through DER, first, a comprehensive list of locations and project types will be prepared in three project areas of: capital upgrade projects, circuit reliability enhancement projects, and maintenance projects. The timeframe of interest to identify projects covers four horizons:

- Near term forecast (1.5-3 years),
- Intermediate term (3-5 years),
- Long term (5-10 years), and
- Ultra-long-term forecast that extends beyond 10-year horizon if supported in existing tools

For each selected DPA, SDG&E will consult with the departments responsible for distribution planning and reliability, asset management, and distribution maintenance to identify upgrade projects for the DPAs selected. Project types will include thermal capacity upgrades (e.g. feeder reconductors or additions, new transformer banks), voltage-related upgrades (e.g. voltage regulators, capacitors, VAr compensators), instrumentation and controls (e.g. SCADA and distribution automation upgrade projects, automation of voltage regulation equipment, voltage instrumentation), reliability upgrades (e.g. cable and equipment replacement projects, switch additions, customer/feeder reduction projects), and maintenance projects (e.g. pole testing and tagging).

Each upgrade project will be described in detail, including a description of the underlying need, equipment lists and project specifications. Each project will be described in terms of the associated services, such as voltage control/regulation. In characterizing each service, the following key definitions and questions will be addressed:

- A detailed description of the service
- How is the service provided today?
- What are the requirements for the service?
- How does location impact the service?
- How would DER provide this service?
- What is the value of the service today?
- What changes to existing processes would be required for DER to provide this service, if applicable?

By virtue of investigating services associated with specific upgrades in the selected DPAs, only electric services that could result in “avoided costs” will be included. One exception is conservation voltage reduction (CVR), which is effectively an energy efficiency service that DERs may be able to provide if controlled and operated by the utility but which is not typically associated with distribution upgrade projects.

Any DER-related installation and operation aspects that are necessary for interconnecting to the utility grid and operating in conjunction with the grid to produce power will not be considered as DER services.

SDG&E will develop a preliminary list of electric services that are currently being provided to customers or potentially can be offered to customers. In addition, a review of industry reports will be performed to expand the list. The literature search will include resources such as CPUC and other PUCs applicable regulation, California ISO and other ISO planning and operations procedures, industry publications, and specialized literature on related topics (e.g., value of solar, etc.). SDG&E will identify key features of these services, assess how DER may benefit/impact them, and outline how the latter could be evaluated.

In addition to reviewing internal processes to determine services, SDG&E will leverage industry experience in this area based on the work done by utilities in other states where high penetration levels of PV systems exist, such as Hawaiian Electric, PEPCO Holdings Inc., Duke Energy, Eversource, etc. to gather data on service classifications and value proposition for DERs.

Step 2: Cost Estimate for Existing Approaches[5]:

For each project identified and documented in step 1, the existing planning-level cost estimation approaches will be utilized to determine planning/budgetary cost estimates for the project.

Currently a typical planning-stage cost estimate for a project consists of the following cost components:

- Engineering and design costs (either contracted or internal including overheads)
- Equipment/material procurement costs (including QC, shipping, warehousing)
- Construction costs (either contracted or internal including overheads)
- Inspection, commissioning and mapping costs
- Project management and site supervision costs

The cost items will sum to a total dollar value that will then receive a contingency adder depending on the nature of cost certainty associated with each project (typically 0%-30%).

SDG&E will use public cost information wherever possible so that this information can be shared among SDG&E and other stakeholders. Any confidential cost information will not be shared publicly or among the IOUs.

Step 3: Project Specifications:

As part of this step, a specification sheet will be prepared for each planned project identified in step 1. The specification sheet will include:

- Project Definition: a description of various needs underlying the identified grid upgrade project. Projects are categorized as
    - Sub-transmission, substation and distribution capacity capital and operating expenditures
    - Distribution voltage and power quality capital and operating expenditures
    - Distribution reliability and resiliency capital and operating expenditures

[5] See section 4.4.1(A) and (B) of the May 2016 ACR

- Project Characterization: determination of electrical parameters for each grid upgrade project, including:
  - Total capacity increase (firm capacity and timing of need),
  - Real and reactive power management schemes,
  - Power quality requirements, and
  - Reliability and resiliency targets;
- Project equipment list: a list of all components and tools required to complete the project, including the specific equipment listed in section 5.5.1 as appropriate:
  - Voltage Regulators
  - Load Tap Changers
  - Capacitors
  - VAR Compensators
  - Synchronous Condensers
  - Automation of Voltage Regulation Equipment
  - Voltage Instrumentation
- Project services and specifications: specifications on how a project will provide the specific services required, including the specific services listed in section 4.4.1:
  - Voltage control or regulation services
  - Reactive supply services
  - Frequency regulation services
  - Power quality services (e.g. mitigation of harmonics, spike, flickers, etc.)
  - Energy loss reduction services
  - Equipment life extensions
  - Improved SAIFI, SAIDI, and MAIFI
  - Conservation voltage reduction
  - Volt/VAr optimization

Step 4: Location Specific Services:

In the next step, a spreadsheet will be prepared to provide location-specific list of applicable electric services as part of each planned distribution upgrade project, for example by feeder or line section. The spreadsheet will be used to develop an illustrative map of the size, types and distribution of the services by the project locations.

Step 5: DER Capability Analysis:[6]

In this step, DER requirements to provide distribution services will be determined. A DER capability analysis will be performed to determine whether a DER can provide the services and if yes, what DER technologies and features will be required to meet the service classifications. The analysis will determine DER characteristics and requirements to provide various electrical services identified and described in Step 3 for each upgrade project and the locational requirements identified in Step 4.

[6] See section 4.4.1(C) of the May 2016 ACR

SDG&E will consider all applicable DER technologies including, per section 4.4.1(B):

- Synchronous generator based DERs, such as gas engines, hydro power plants, bio-mass units and combined heat and power (CHP) plants, or any other similar technologies.
- Power electronic based DERs utilizing "standard" (conventional) inverters/converters (with limited power factor or control capabilities), such as presently deployed UL-certified PV inverters, and,
- Power electronic based DERs utilizing "smart" (advanced) inverters/converters functionalities, such as bidirectional and four-quadrant battery energy storage systems, and advanced PV inverters.

A high-level qualification table, as an example, is shown below.

Table 1 – Qualification of DER capability in providing a special service

Services	CHP	Standard Inverters				Smart Inverters			
		PV	Fuel Cell	Wind Type 4	Energy Storage	PV	Fuel Cell	Wind Type 4	Energy Storage
Voltage control/regulation	High (certain types)	None	None	None	Medium (kVA limit)	Medium (Production Priority)	Medium (Production Priority)	Medium (Production Priority)	High (certain types)
Reactive supply	High (certain types)	Low (limited pf range)	Low (limited pf range)	Low (limited pf range)	Medium (kVA limit)	Medium (Production Priority)	Medium (Production Priority)	Medium (Production Priority)	High (certain types)
Frequency regulation	Low (slow response time)	None	None	None	High (certain types)	Low (uni-directional)	Low (uni-directional)	Low (uni-directional)	High (certain types)

In addition to the DER capabilities to provide the service, SDG&E will investigate and describe any changes that need to be applied into existing processes to support certain services through DERs.

<u>Phase 3: Calculation of Locational Net Benefits</u>

A total avoided cost will be calculated for each location in the selected DPA(s). Per table 2 of the 5/2/2016 ACR, this will include

1. Avoided T&D
2. Avoided Generation Capacity
3. Avoided Energy
4. Avoided GHG
5. Avoided RPS
6. Avoided Ancillary Services
7. Renewable Integration Costs, Societal Avoided Costs and Public Safety Avoided Costs

Components 2-6 above will be borrowed from the DERAC model with exception that a flexibility factor will be added to incorporate avoided flexible capacity into component 2. Component 7 will be described qualitatively with the exception that the default renewable integration costs from the RPS Proceeding will be incorporated.

The avoided T&D cost will be calculated using the Real Economic Carrying Charge method to calculate the deferral value for each project. These will be assigned to one of the four subcategories below:

1. Sub-transmission, substation and distribution capacity capital and operating expenditures
2. Distribution voltage and power quality capital and operating expenditures
3. Distribution reliability and resiliency capital and operating expenditures
4. Transmission capital and operating expenditures

The joint IOUs have engaged Energy and Environmental Economics (E3), the original developer of the DERAC tool, to develop detailed LNB methodologies and a tool implementing those methodologies. A preliminary description of the detailed methodologies is provided in **Appendix C.**

This tool will be made public as will inputs and other data to the extent this information is not confidential. As indicated previously, SDG&E will use public inputs and data wherever possible.

Phase 4: Visualization of Information

As part of this task, the LNBA Demo B maps will be created that can be overlaid on the Integration Capacity Analysis results. Per section 4.4.2 of the 5/2/2016 ACR, three separate maps will be created:

1. Locations of upgrade project areas with details, associated services and, where appropriate, location-specific DER specifications
2. DER growth heat maps
3. LNBA results heat map showing the total avoided cost across selected DPAs based on public information

The maps will include opportunities for conservation voltage reduction (CVR) and volt/VAr optimization services, and any additional services that are deemed feasible in the analysis.

IV. *Detailed Schedule and Stakeholder Engagement*

List of Tasks and Schedule

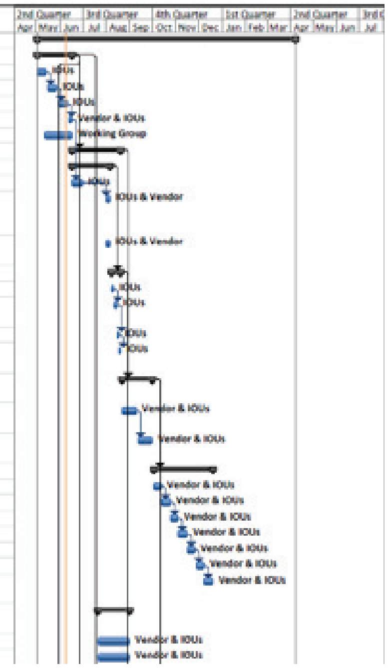
The Gantt chart below captures the proposed implementation plan for the locational net benefits methodology/analysis to be conducted by SDG&E. The schedule consists of six primary tasks. The first and last tasks address the initial planning, and the monitoring and reporting of progress, respectively. The remaining tasks contain the detailed activities required to execute the four phases of the project described in detail elsewhere in this document, namely Phase 1 - Planning Area Selection, Phase 2 - Identify and Describe Distribution Upgrade Projects in Selected Planning Area, Phase 3 - Calculation of Locational Net Benefits and Phase 4 - Visualization of Information.

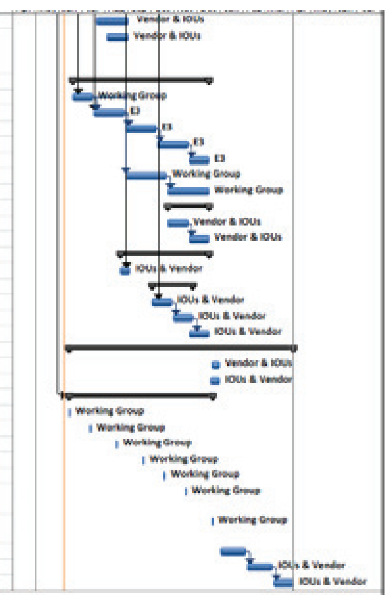
To ensure progress is monitored, the schedule makes provision for monthly working group meetings. These meetings will have two goals; the first is to review activities and track progress, the second is to focus on key technical aspects relevant to activities at that juncture in the project. The Gantt chart identifies the technical focus area for each meeting.

Some of the activities have to be executed sequentially and the Gantt chart documents these dependencies. Some of the activities are time-bound and must be completed by a certain date, and the Gantt chart back-calculates the sequencing of activities to ensure the deadlines are met. The Resource Names column identifies which of the team members is responsible for executing that specific activity. When more than one name is listed, the first team member listed has lead and any subsequent team member(s) have supporting roles.

Demonstration B Gantt Chart

ID		Task Mode	Task Name	Duration	Start	Finish	Predecessors	Resource Names
1			**LNBA Implementation Plan**	**245 days**	**Mon 5/2/16**	**Fri 4/7/17**		
2			**Complete and File Implementation Plan**	**34 days**	**Mon 5/2/16**	**Thu 6/16/16**		
3			Methodology description	10 days	Mon 5/2/16	Fri 5/13/16		IOUs
4			Load forecasting description	10 days	Mon 5/16/16	Fri 5/27/16	3	IOUs
5			Initial considerations for DPA selection and Demo projects	10 days	Mon 5/30/16	Fri 6/10/16	4	IOUs
6			Prepare schedule and Gantt chart	4 days	Mon 6/13/16	Thu 6/16/16	5	Vendor & IOUs
7			Working group participation and reporting	26 days	Thu 5/12/16	Thu 6/16/16		Working Group
8			**Review and finalize Demo B projects (LNBA)**	**46 days**	**Fri 6/17/16**	**Fri 8/19/16**	**2**	
9			**Characterization and selection of DPAs**	**36 days**	**Fri 6/17/16**	**Fri 8/5/16**		IOUs
10			Perform load forecasting	10 days	Fri 6/17/16	Thu 6/30/16	6	IOUs
11			List of all upgrade projects in DPAs (cable replacement, SCADA enhancement, equipment change, etc.) - irrespective of DER scenarios	5 days	Mon 8/1/16	Fri 8/5/16	10	IOUs & Vendor
12			List of all voltage support/power quality or reliability/resiliency related projects	5 days	Mon 8/1/16	Fri 8/5/16		IOUs & Vendor
13			**Finalize selection of Demo B projects**	**10 days**	**Mon 8/8/16**	**Fri 8/19/16**	**9**	IOUs
14			Select one Capital project	3 days	Mon 8/8/16	Wed 8/10/16		IOUs
15			Select one voltage quality / reliability / maintenance related project	3 days	Thu 8/11/16	Mon 8/15/16	14	IOUs
16			Select one near term and One long-term time frame	2 days	Tue 8/16/16	Wed 8/17/16	15	IOUs
17			Select territory diversity (e.g. one urban and one rural area) projects	2 days	Thu 8/18/16	Fri 8/19/16	16	IOUs
18			**Determine additional upgrade projects based on the two DER growth scenarios**	**30 days**	**Mon 8/22/16**	**Fri 9/30/16**	**8**	
19			Include projects from distribution planning process, circuit reliability improvement process, and maintenance process	15 days	Mon 8/22/16	Fri 9/9/16		Vendor & IOUs
20			Identify possible elimination or incremental upgrade projects based on High DER forecast	15 days	Mon 9/12/16	Fri 9/30/16	19	Vendor & IOUs
21			**Document upgrade projects**	**56 days**	**Mon 10/3/16**	**Mon 12/19/16**	**18**	
22			Location and type of projects	8 days	Mon 10/3/16	Wed 10/12/16		Vendor & IOUs
23			Project specifications	8 days	Thu 10/13/16	Mon 10/24/16	22	Vendor & IOUs
24			Parameters of the projects	8 days	Tue 10/25/16	Thu 11/3/16	23	Vendor & IOUs
25			Need identified in upgrade project	8 days	Fri 11/4/16	Tue 11/15/16	24	Vendor & IOUs
26			Equipment necessary for upgrades	8 days	Wed 11/16/16	Fri 11/25/16	25	Vendor & IOUs
27			Estimated cost of upgrade using traditional methods	8 days	Mon 11/28/16	Wed 12/7/16	26	Vendor & IOUs
28			Determine timeframe of upgrades (short-term, near-term, and long-term)	8 days	Thu 12/8/16	Mon 12/19/16	27	Vendor & IOUs
29			**Review and finalize full range of electric services by DER for avoided costs in all locations**	**30 days**	**Thu 7/21/16**	**Wed 8/31/16**		
30			Identify need attributes that DERs could potentially defer	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
31			Identify area in which DERs must locate to mitigate need	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
32			Identify location-specific electric services associated with projects	30 days	Thu 7/21/16	Wed 8/31/16		Vendor & IOUs
33			Determine DER capabilities and specifications to offer the services Include capabilities of standard and smart inverters as well as synchronous machines	20 days	Thu 8/4/16	Wed 8/31/16		Vendor & IOUs
34			**Develop LNBA tool (E3 tool) plus additions**	**130 days**	**Mon 6/20/16**	**Fri 12/16/16**		
35			Methodology	20 days	Mon 6/20/16	Fri 7/15/16	2	Working Group
36			RECC method for avoided cost of projects	30 days	Mon 7/18/16	Fri 8/26/16	2,35	E3
37			DERAC values for energy and capacity	30 days	Mon 8/29/16	Fri 10/7/16	36	E3
38			Include flexible capacity "flexibility factor"	30 days	Mon 10/10/16	Fri 11/18/16	37	E3
39			Include renewable integration costs	20 days	Mon 11/21/16	Fri 12/16/16	38	E3
40			Determine a list of potential societal or public avoided costs	40 days	Mon 8/29/16	Fri 10/21/16	35	Working Group
41			Defining the associated project specific metrics	40 days	Mon 10/24/16	Fri 12/16/16	40	Working Group
42			**Calculate total LNB for Demo B specific locations and projects**	**40 days**	**Mon 10/24/16**	**Fri 12/16/16**		
43			Perform LNBA for Demo B Project group 1 (capacity type)	20 days	Mon 10/24/16	Fri 11/18/16		Vendor & IOUs
44			Perform LNBA for Demo B Project group 2 (non-capacity type)	20 days	Mon 11/21/16	Fri 12/16/16	43	Vendor & IOUs
45			**Create a LNBA map by locations**	**85 days**	**Mon 8/22/16**	**Fri 12/16/16**		
46			Initial mapping of upgrade projects (spreadsheet and visualization)	10 days	Mon 8/22/16	Fri 9/2/16	13	IOUs & Vendor
47			**Present services on maps and describe in writing**	**40 days**	**Mon 10/3/16**	**Fri 11/25/16**		IOUs & Vendor
48			Develop machine readable format (Spreadsheet)	20 days	Mon 10/3/16	Fri 10/28/16	18	IOUs & Vendor
49			Develop scripts and tools for transferring to maps and visualizing	20 days	Mon 10/31/16	Fri 11/25/16	48	IOUs & Vendor
50			Examine and publish overlay on the map (go live)	20 days	Mon 11/21/16	Fri 12/16/16	49	IOUs & Vendor
51			**Monitoring and Reporting**	**213 days**	**Wed 6/15/16**	**Fri 4/7/17**		
52			*Demo B Report*	*8 days*	*Wed 12/21/16*	*Fri 12/30/16*		*Vendor & IOUs*
53			*Intermediate report on long term enhancements*	*10 days*	*Mon 12/19/16*	*Fri 12/30/16*		*IOUs & Vendor*
54			**Reporting to the working group**	**136 days**	**Wed 6/15/16**	**Wed 12/21/16**	**2**	
55			June Meeting (LNBA Plans submitted to CPUC June 16th)	1 day	Wed 6/15/16	Wed 6/15/16		Working Group
56			July Meeting (Review Demo Project A and data)	1 day	Wed 7/13/16	Wed 7/13/16		Working Group
57			August Meeting (Update on Pilot Projects)	1 day	Wed 8/17/16	Wed 8/17/16		Working Group
58			September Meeting (LNB Methodology: Deep Dive)	1 day	Wed 9/21/16	Wed 9/21/16		Working Group
59			October Meeting (LNB Maps: Discussion on Output Format)	1 day	Wed 10/19/16	Wed 10/19/16		Working Group
60			November Meeting (LNB Methodology: Calculated LNBs from Pilot Projects and Development of Requirements)	1 day	Wed 11/16/16	Wed 11/16/16		Working Group
61			December Meeting (Report Submitted/ LNB Maps: Lessons Learned and Future Refinements)	1 day	Wed 12/21/16	Wed 12/21/16		Working Group
62			Stakeholder Review	25 days	Mon 1/2/17	Fri 2/3/17		
63			Enhancements	25 days	Mon 2/6/17	Fri 3/10/17	62	IOUs & Vendor
64			*Final report*	*20 days*	*Mon 3/13/17*	*Fri 4/7/17*	*63*	*IOUs & Vendor*





Project: Schedule - V1
Date: Wed 6/8/16

Task | Split | Milestone | Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | Deadline | Progress

Page 2

Stakeholder Engagement: Working Group Report out Schedule and Metrics

The schedule below provides an expected ordering of Demo B report outs to the LNBA WG in 2016. It does not include other WG activity, such as discussions on long-term refinements to LNBA.

- June (Complete) – Working group role and review of Demo B requirements
- June (Complete) – More detail on Implementation Plans, present selected DPAs
- July – LNB methodology deep dive #1
    - IOUs will and possibly their consultant(s) will present for discussion the Implementation Plan process and detailed methodologies. Areas for additional clarification or development will be identified.
- August – Review Demo B progress and data on upgrade projects
    - IOUs will present preliminary list of upgrade projects in Demo B DPAs.
- September – Review Demo B progress and review preliminary list of electric services
    - IOUs will review their preliminary list of electric services with other IOUs and stakeholders as part of the working group activities, incorporate comments and suggestions, answer questions, and identify gaps that require more extensive research.
- October – Mapping and output format
    - IOUs will seek input on the format of LNBA results, prioritization of LNBA map features.
- November – LNB methodology deep dive #2
    - IOUs will present for discussion Demo B process and methodologies to date, with an emphasis on areas identified in July for additional clarification or development. If possible, a preliminary version of the E3 tool will be shared at this point.
    - IOUs will present for discussion preliminary results on upgrade deferral values and DER requirements.
- December – Present draft Demo B Report and lessons learned
    - IOUs will present draft LNBA maps and will seek input on lessons learned from Demo B and recommendations. IOUs will compare calculated LNB results to existing system-wide estimates of T&D benefits.

In addition, SDG&E proposes to report out their estimated percent completion metric on the major phases and steps identified in this document on a monthly basis.

V. Conclusion

SDG&E believes this implementation plan meets the requirements as specified in the ACR issued May 2. The implementation plan contains the following tasks:

1. A description of the revised LNBA methodologies as specified in Section 4.4.1
2. A description of SDG&E's load forecasting/characterization methodology tool used for the LNBA
3. Includes a Gantt Chart of the LNBA development process
4. Includes a plan for a monthly monitoring and reporting to the Demo B Working Group

SDG&E appreciates the opportunity to provide this Demonstration B Implementation Plan and looks forward to the collaborative efforts that are currently underway in the Demo B Working Group.

Appendix A – Load forecasting

As a part of the LNBA SDG&E has and will continue to refine its distribution load forecasting to include the impacts of future DERs on load growth. SDG&E has already modified its load forecasts to account for the present day reduction in load due to existing DER's by modifying load profiles to include all downstream DER generation output coincident with the load on each circuit. SDG&E is also incorporating the growth scenarios from the DRP to include DER deployment forecasts in order to appropriately modify future forecasted load profiles. SDG&E will work to develop or use third party DER forecasts that have a high degree of certainty in order to insure that capacity and reliability issues do not arise as a result of over/under optimistic DER forecasts.

SDG&E plans to utilize LoadSEER to develop its forecasted load shapes that are uploaded to Synergi for the LNBA. LoadSEER will allow SDG&E to progress from the existing point-in-time forecast to an hourly demand-curve type forecast. The advancement enables SDG&E to perform power flow analysis against multiple DER profiles throughout the day. This tool employs multiple statistical methods including SCADA as well as weather data throughout SDG&E service territory to derive statistical modeling of peak load history, econometric modeling of energy, and a GIS-based land use simulation analysis (spatial forecasting) all of which are used to develop forecasted load shapes. LoadSEER assigns CEC system level mid case demand to the appropriate substations and circuits to establish the growth by utilizing the statistical methods described previously. The two DER growth scenarios (scenario I and scenario III) established by SDG&E with the IEPR forecast mid-energy demand case as the base will also be included in the forecasted load shapes. The final product will be a typical high load forecasted load shape day and a typical low load forecasted load shape day for each month for the next 10 years. A detailed description of LoadSEER is available within SDG&E filed DRP.

Appendix B – Proposed Demo B DPA

The ACR instructs the utilities to apply the LNBA as part of Demonstration Project B to a Distribution Planning Areas (DPA). SDG&E has chosen its Northeast and Ramona districts as the DPA in which to implement Demonstration Project B. Figure 1 below shows these this DPA within SDG&E's service territory.

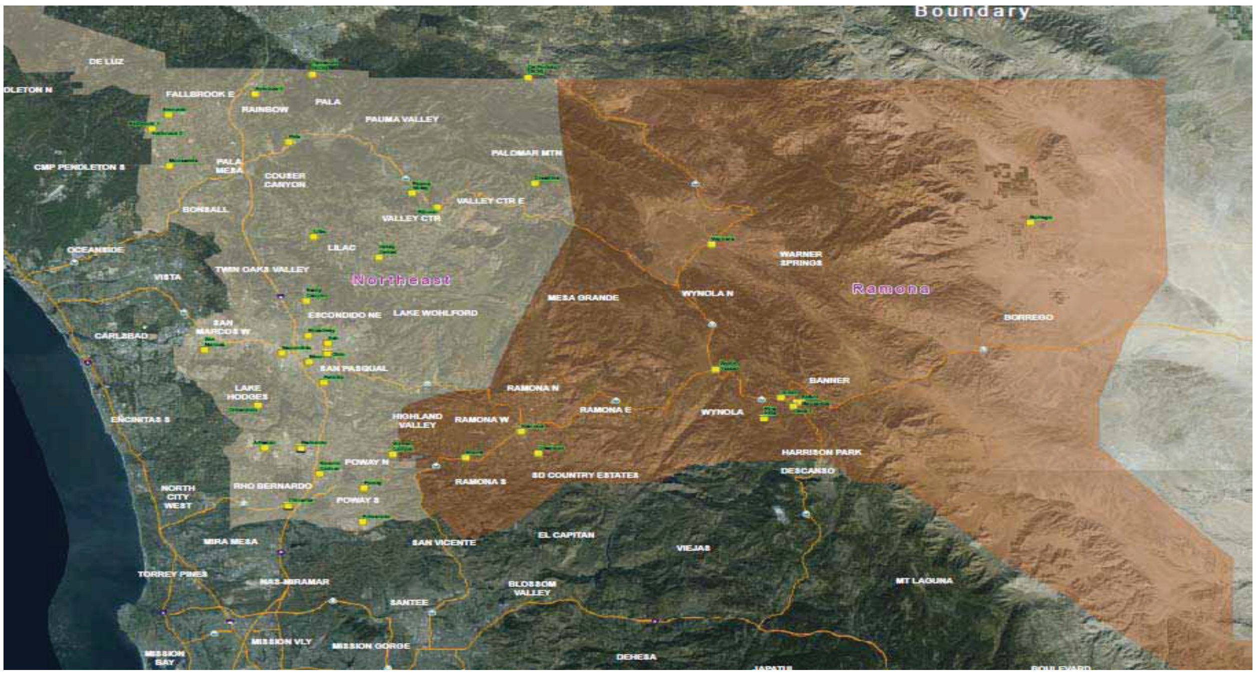


Figure 1. Northeast and Ramona Districts

This DPA represent one urban/suburban and one rural DPA within the SDG&E territory. The intent of picking a DPA from each of these categories is to get varying characteristics in which to evaluate varying conditions in the system. The other goal is to drive coordinated learnings with the other demonstration projects. Here is some general information about the DPA:

Table 1: Northeast and Ramona Statistics

	Northeast	Ramona
Total Customers	210618	20917
Residential	183720	17303
Industrial	120	7
Commercial	26778	3607
Circuits	150	27
Substations	29	11

Appendix C to Attachment 2

Locational Net Benefit Analysis Modeling for Demonstration B

Contents

1 Introduction

E3 was retained by the three investor owned utilities (IOUs) in this proceeding to build a simple model for estimating location-specific avoided costs of installing distributed energy resources (DERs) based on a specific approved LNBA methodology framework provided to the utilities by Assigned Commissioner Picker's ruling of May 2, 2016 (ACR) for Demonstration B. The model is based upon the ACR's requirements and publicly available information. The IOUs requested E3 prepare this model to ensure consistency with the prescriptive directives of the ACR regarding the structure of the LNBA and to facilitate Commission evaluation of the LNBA methodology. This document describes the modeling used for calculating the locational net benefits (LNBs) for the IOUs' Demonstration B projects (Demo B Modeling), and was developed by E3. The model (LNBA tool) will be made public to allow for review of the methodology, but actual utility-specific input values are not intended to be disclosed to market participants.

The Demo B Modeling includes system level avoided costs associated with load changes from DERs, including those from the DER Avoided Cost (DERAC)[1] (avoided energy, generation capacity, losses, ancillary services and avoided RPS and GHG compliance costs), flexible resource adequacy (RA) capacity, and an integration cost adder. E3 presents a framework to calculate local avoided costs of DERs in greater detail than in previous tools. This involves replacing the T&D component used in the DERAC explicitly with more detailed and location-specific avoided cost categories indicated in the ACR:

1. Avoided sub-transmission, substation and distribution capacity capital and operating expenses
2. Avoided distribution voltage and power quality and operating expenditures
3. Avoided distribution reliability and resiliency capital and operating expenditures
4. Avoided transmission capital and operating expenditures

In addition, conservation voltage reduction (CVR) opportunities will be considered.

[1] The latest DERAC tool is available here: https://ethree.com/public_projects/cpuc5.php

E3 has investigated how each of the above potential avoided costs can be calculated for Demo B through discussions with the IOUs. The following methodological components are employed in the Demo B Modeling for each of the above avoided costs:

1. **Avoided sub-transmission, substation and distribution capacity capital and operating expenses.**

   These investments are needed to safely and reliably accommodate load-growth. The avoided cost for this category follows the deferral methodology presented in the document below. Operating expenses would be an annual savings during the years of deferral or an ongoing annual savings if the investment can be avoided. If the construction of the original project would reduce capital and/or operating expenses elsewhere, those cost savings would be accounted for to correctly evaluate the *net* change in capital and operating cost.

2. **Avoided distribution voltage and power quality and operating expenditures**

   Discussions with the IOUs indicate that the driver for some of these investments could also be load growth. The LNBA model will allow avoided cost estimation for such growth-related investments. These investments may be more localized due to, for example, voltage issues at the end of a circuit. Depending on the nature of the voltage and power quality avoided upgrade identified, the geographic scope of these projects may be different from upgrades identified in category 1. Several category 2 sub segments may exist within the affected region of a category 1 upgrade. Volt/VAr opportunities are considered in this category.

   DERs have been identified as causing potential voltage issues, particularly in the case of distributed generation photovoltaics (DGPV). Currently DER penetration has not been large enough to cause voltage issues that require utility corrective investments. Hence DERs installed prior to smart inverter rollout would not avoid any investments.

   Smart inverters are designed to mitigate the voltage issues, and it is expected that smart meter development and deployment will be sufficient to mitigate DER-caused voltage issues that may occur in the future. Since going forward Smart Inverters will be a mandatory requirement in the CAI IOU interconnection tariffs, there will be opportunities for mitigating these potential voltage issues in the interconnection process. Consequently, voltage projects driven by DER penetration are not considered in this analysis. Furthermore, improvements beyond current standards for voltage and power quality are assumed to have zero avoided cost value because there are no investments scheduled to improve voltage beyond Rule 2 value and power quality.

3. Avoided distribution reliability and resiliency capital and operating expenditures

Reliability and resiliency projects are primarily driven by factors such as equipment age and condition, equipment location and system configuration, remote communication and control and disturbance events that result in outages. The provision of reliability and resiliency improvements would require the ability of the DER to improve system metrics such as SAIDI, SAIFI and MAIFI. There may be cases where unloading of the demand on existing equipment could allow for the existing equipment to continue to provide adequate service and defer equipment upgrades or replacements (e.g.: where the load reduction allows for an existing backtie to support the cutover of load during a disturbance event). The LNBA tool would use the deferral methodology to develop avoided costs for the demand reductions needed to relieve the existing equipment in those cases.

There may also be cases where the ability to operate an area as an island (e.g.: micro-grid applications) offer the opportunity for extensive DER in combination with other enabling technologies and investments to defer or replace the need for traditional reliability improvements to the area. The LNBA Tool deferral framework could be applied in those cases by evaluating DER impacts on load in all hours rather than just the peak period.

4. Avoided transmission capital and operating expenditures

The framework can be applied to any level of geographic specificity from line segment to CAISO system level. DERs can have avoided costs related to several levels. Load-growth-driven transmission avoided costs can either be calculated the same way as category 1 investment deferrals using system level data inputs, or estimates from other modeling approaches such as the NEM public tool can be used.

This category potentially overlaps with local RA capacity. In the cases where RA capacity is an avoided cost applicable to installed DER in the region, the model will use the lower of 1) the incremental value of local RA above system RA capacity, or 2) the avoided cost of an identified transmission project that would eliminate the local RA price premium (using the deferral methodology described below for transmission and sub-transmission level investments).

Conservation voltage reduction

Benefits in this category include greater energy efficiency and potentially reduced wear and tear on equipment such as tap changers. Unlike the other distribution value streams discussed above, the benefits of CVR would not accrue from the deferral of planned utility investments, but rather from energy savings and potentially distribution expense savings. As such, CVR would not be evaluated using the deferral methodology in the LNBA Tool, but would be incorporated via an adder to the avoided cost of energy. The benefits of CVR will only be achievable if the DER is operated in a coordinated fashion by the utility to lower the voltage and avoid energy consumption. Evaluation of CVR strategies and their potential impacts remain ongoing, and the magnitude of any adder would be specific to both the area of concern and the DER technologies and enabling technologies under consideration. The determination of any adder would be conducted outside of the LNBA Tool.

The avoided costs identified in the above categories are determined in the Demo B Modeling by calculating the deferral value of the investments identified to address a need on the system, whether they are for local or system level transmission infrastructure, voltage and power quality, or reliability and resiliency.

1.1 Other LNBA Tool functionality

In addition to estimating the localized avoided cost of the distribution services listed above, the LNBA tool will assign the costs to the local peak period, allow for avoided costs to be aggregated or pancaked when a DER in an area can affect multiple projects, and calculate the avoided cost benefits of various DER options.

The LNBA tool uses hourly allocation factors to represent the relative need for capacity[2] throughout the year. Three options for determining the hourly allocation factors are discussed here.

[2] Throughout this document "capacity" refers to distribution capacity unless indicated otherwise, such as generation capacity or DER nameplate capacity.

To determine the avoided cost benefits of DER technologies, the LNBA Tool calculates the coincidence of the technology's dependable capacity contribution with the capacity need. For example, solar peaking in daytime hours will have very little dependable capacity contribution, and therefore deferral value, for an investment on a nighttime peaking feeder.

The use of dependable capacity, rather than the simple expected capacity contribution from DERs is important as the distribution areas become smaller and the number of feasible DER becomes smaller and therefore less diverse. Dependable capacity is also important for areas with high levels of DER that are weather sensitive (such as PV), as weather variations could result in large variations in net loads for the area. Dependable capacity contribution is the number of MWs of peak load reduction that a DER technology can be relied upon to produce for the purposes of capital investment planning. The model will include inputs for the IOUs to define a level of risk at the distribution level that helps determine a DER's dependable capacity contribution. Techniques to determine the dependable capacity contribution are presented for different DER types.

The LNBA Tool will incorporate the system benefits from the CPUC Avoided Cost Model (ACM) that is currently being updated. The Tool will also add the value of flexible capacity (an avoided cost component that is not included in the ACM update at this time).

2 Methodology

The locational avoided cost of installing a DER is the deferral benefit of moving investments in new T&D capacity from the original installation year to a year in the future. The T&D capacity value of a DER resource is dependent on how much capacity a resource can reliably offer during peak load times, and the subsequent realizable deferrals. For example, consider energy efficiency measures that on aggregate reduce load by 1 MW during peak load hours. Assuming that 1 MW reduction can be reliably counted on during peak load hours, the contribution towards deferral will be 1 MW. However, distribution planners have to be confident that, firstly, the energy efficiency measures are providing a dependable reduction of 1 MW, and secondly that the measures meet criteria necessary to result in deferrals.

Assessing whether a DER plan meets these criteria, and defining the assessment criteria themselves, are covered in the following methodology sections:

Deferral Value. Different methods for evaluating deferral benefits, given forecasted future net loads, are described. Uncertainty around the expected deficiency that triggers investments can be incorporated as sensitivities in the model. Adequately determining the load forecast specific to the distribution system below the point of deferrable investment is important to ensure deferrals can actually be realized. Load forecasting and its treatment in deferral evaluation are discussed. Finally, this section covers the minimum deferral criteria.

1. **DER measure of coincidence with peak load.** The coincidence of the DER's reduction in load with the highest load hours is essential. The higher the coincidence, the greater the measure's contribution to peak load reductions, and the higher it's capacity value. To evaluate this coincidence, the LNBA Tool calculates a probability of capacity need for all of the distribution area peak hours. This is discussed below in section 2.2. The uncertainty in load growth is incorporated through sensitivities, while the uncertainty around DER impact is incorporated through calculating a dependable output of DER.
2. **Dependable output of DER.** This is the load reduction caused by a DER measure that a resource planner can trust to actually occur, and can therefore factor into decisions on what capacity to build. The actual dependable load reduction can vary depending on the risk profile of the local

system, and the set of resources installed. This can take the form of a derate on output for measures such as energy efficiency and storage to account for outages. However, determining the dependable load reduction is particularly important for weather-dependent DERs because of the uncertainty in their output. Dependable capacity will also depend on the penetration of existing DER due to shifting coincidence with load as more DER is added. The methodology for calculating dependable capacity is explained in section 2.3.

2.1 Deferral Value

2.1.1 INVESTMENT PLAN

The estimation of T&D project capacity costs requires the development of a T&D supply plan. T&D capacity investments should include only work and materials that could be deferred by DERs. To the extent there are non-deferrable costs identified, these will be described, quantified and ultimately excluded from the deferral benefit calculation. Examples of costs that would not be included are:

- Costs for related work that is not deferrable by DERs - Facilities that are not deferred should be excluded because adoption of DERs has no effect on them. For example, a new circuit may relieve capacity constraints, but also eliminate the cost of connecting a new subdivision to the utility grid. If a DER defers the need for a new circuit but the utility must proceed with the work of connecting a new subdivision, then the latter's costs could not be deferred, and the costs should be excluded from the deferral benefit.
- Sunk costs - Expenditures that would need to be made prior to date when the utilities could defer the project should be excluded, as those costs also cannot be deferred.

The distribution plan costs should also be adjusted for any higher costs that the utility might incur from deferring construction. An example of this type of cost is storage fees. In one local integrated resource planning (LIRP) study performed by E3, a utility had already commissioned the construction on long lead time custom underground cable. The cable could not be re-sold to any other utility, nor could the utility store the cable on its properties. The cost of storing the cable at the manufacturer or third party sites was high enough to rule out any DER opportunities for cost effective deferral of the underground project. The higher costs from deferral should be reflected through a high equipment inflation rate. For example, if the cost of the project would increase by 10% each year the project is deferred, an inflation rate of 10% should be used instead of a default CPI-based inflation rate (typically 2% or lower).

There is uncertainty in the cost of facilities until they are procured because of changes in the cost of equipment between the time the plan is developed and the actual procurement of the equipment. The Investment costs will be represented by high, medium, and low estimates.

2.1.2 DEFERRAL VALUE

The essence of the Deferral Value is the present value revenue requirement cost savings from deferring a local expansion plan for a specific period of time. The LNBA Tool is proposed to estimate deferral value in three ways discussed below.

1. **Discrete Deferral Value ($).** The present value of savings accrued by deferring a project are calculated using the Real Economic Carrying Charge (RECC). RECC converts capital cost into an annual investment cost savings resulting from a discrete period of deferral. The Discrete Deferral value will require the user to specify the number of years of deferral (e.g.: 3 years). The value will be presented as:
    a. High, medium and low dollar savings ($) along with information on the peak reductions needed to attain those savings. Peak reductions would be shown as:
        i. High, medium and low peak MW reduction, with indication of peak hours (month, hour range, etc). The range of peak load reduction is driven by the load forecast and the uncertainty around it.
        ii. High, medium and low nameplate DER installs by technology to attain the reduction if each were the only technology implemented. The model includes a relationship between installed nameplate and dependable capacity.
2. **Discrete Savings per kW ($/kW).** This is the Discrete Deferral Value divided by the kW needed to attain the deferral. High medium and low savings per kW would be produced. High would mix high cost and low kW, medium would be medium cost and medium kW, and Low would be low cost and high kW. Three sets of values would be produced:
    a. High medium and low $/kW values, where the kW is the peak load reduction. This is not specific to a DER technology.
    b. High medium and low $/kW values, where the kW is DER nameplate kW required to achieve the deferral. These values would be technology specific.

c. Low value of zero if insufficient peak reduction were available to enable deferral.

3. **Avoided Cost ($/kW-yr).** This is the single year discrete deferral value (calculated following the methodology above in 1.) divided by the kW needed to attain the deferral. High medium and low savings per kW-year would be produced. This is calculated similar to the Discrete Savings per kW, except that a single year deferral is used. Note that if there are multiple investments in the plan with different service lives, the RECC for each would vary. Two sets of values would be produced:
    a. High medium and low $/kW-yr values per kW of peak load reduction. As discussed above, the range would be produced by combining the range of investment costs and the range of needed kW, and is not DER technology specific.
    b. High, medium and low $/kW-yr values per kW of DER nameplate. These values would be technology specific. As discussed above, the range would be produced by combining the range of investment costs and the range of needed kW. The range will not reflect uncertainty in peak contributions from technologies.

2.1.3 FORMULAS AND EXAMPLE CALCULATIONS

Figure 1**Error! Reference source not found.** illustrates a situation where a network T&D investment is needed and the project cost. The project is needed to prevent the load growth (net of naturally occurring DER) from exceeding the T&D facility's load carrying capability and allows time for project deployment prior to the actual overload. In Figure 2**Error! Reference source not found.**, the utility is targeting incremental load reduction from the red line to the green line to allow the investment to be deferred by 3 years. The deferred project's cost is slightly higher due to equipment and labor inflation costs, but this would be more than offset by the financial savings from being able to defer the project.

Figure 1. Investment in distribution project due to load growth

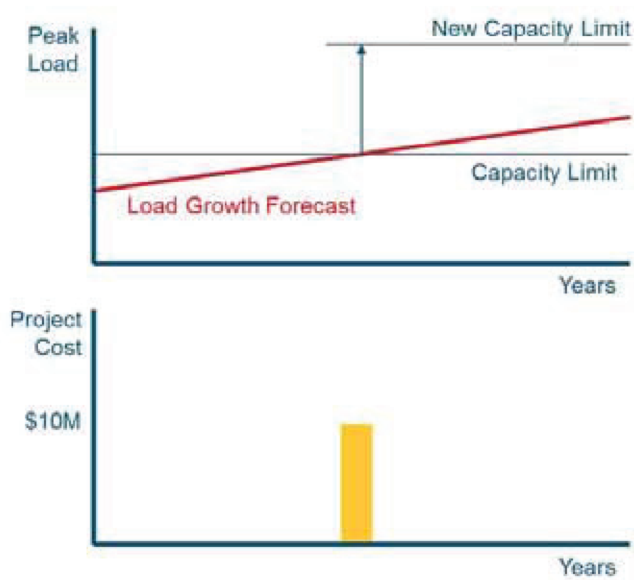
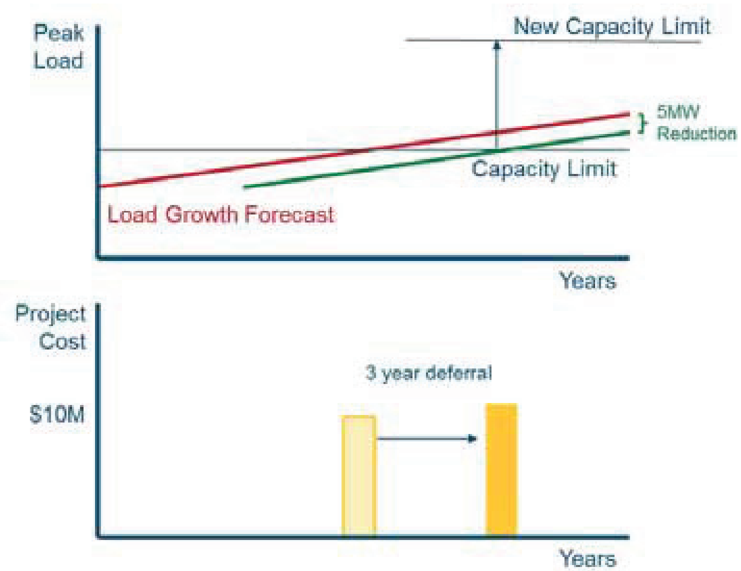


Figure 2. Project deferral of distribution investment



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Other Assumptions:

- Original Investment cost (low, med, high): $8M, $10M, $15M
- Annual incremental operating cost: $0.1M, $0.2M, $0.4M
- Asset life: 40 years
- Load reduction needed for 2 year deferral: 4MW, 6MW, 8MW
- Load reduction needed for 1 year deferral: 2MW, 3MW, 4MW
- Revenue Requirement Scaling factor: 150%
- WACC: 7.5%
- Inflation: 2%
- *RECC = 5.24%*

Note that the quantities and inputs used in this example are purely illustrative and may not resemble the inputs used in Demo B or their ranges.

Discrete Deferral Value

The savings of one year of deferral ($/yr) is:

$$SavingsOne = TDCapital[y] * RECC * RRScaler[y] + \Delta O\&M$$

The savings of multiple years of deferral is:

$$SavingsTotal = SavingsOne * \sum_{d=1}^{D} \left(\frac{1+i}{1+r}\right)^{d-1}$$

Where:

TDCapital	=	Capital cost of the investment in year y. Note that the capital cost should be entered in the year that the expenditure stream is committed, which is likely to occur before the in-service year. The costs are lumped together to the commitment date, rather than the construction dates. However, if the project is structured such that there are major work stages that could be deferred separately, then each of the stages of work could be entered as a separate lump sum corresponding to each independent commitment date. Similarly, if there are multiple projects that have different commitment dates within the analysis horizon, each of those projects could be entered as independent lump sum values.
RECC	=	Real economic carrying charge. $RECC = \frac{(r-i)}{(1+r)} \frac{(1+r)^n}{[(1+r)^n-(1+i)^n]}$
RRScaler[y]	=	Revenue requirement scaling factor to convert direct capital costs to revenue requirement levels in year *y*. The scaling factor reflects the cost impacts of factors such as taxes, franchise fees, return on and of capital, administrative overhead, and general plant costs. The scaling factor can also vary with the utility book life of each asset.
ΔO&M	=	Incremental annual cost of O&M associated with the investment
i	=	*Inflation for T&D equipment*
r	=	*Discount rate (WACC)*
n	=	*Deferred Asset's life*
D	=	*Total years of deferral*

Table 1: Example Discrete Deferral Results ($millions)

Item	Variable	Low	Med	High
Investment Cost	TDCapital ($M)	$8.00	$10.00	$15.00
	RECC	5.25%	5.25%	5.25%
	RRScaler	150%	150%	150%
Incremental O&M	ΔO&M ($M/yr)	$0.20	$0.30	$0.40
One year Deferral	**SavingsOne ($M)**	**$0.83**	**$1.09**	**$1.58**
Two year Deferral	**SavingsTotal ($M)**	**$1.62**	**$2.12**	**$3.08**

One year savings based on reductions of 2MW to 4MW, during the hours of …
Two year savings based on reductions of 4MW to 8MW, during the hours of…

Discrete Savings per kW

DiscreteperkW = SavingsTotal / MWNeed * 1000

Where

SavingsTotal = The Discrete Deferral value for D number of years of deferral, in millions

MWNeed = MW reduction needed to attain D years of deferral

Table 2: Example of Discrete Savings per kW (based on load reduction need, not DER technology) for a 2 year deferral

Value	Variable	Low	Med	High
Two-year Deferral	SavingsTotal ($M)	$1.62	$2.12	$3.08
MW Need (Hi, Med, Lo)	MW Need (2 yr)	8	6	4
Discrete savings per kW	DiscreteperkW	$202	$353	$770

Note that there will be zero savings if insufficient MW reductions are modeled to allow deferral of the project

Avoided Cost ($/kW-yr)

AvoidedCost = SavingsOne / MWNeed * 1000

Example of avoided costs per kW-yr (based on need, not DER technology)

Table X: Example of Discrete Savings per kW (based on load reduction need, not DER technology) for a 1 year deferral

Value	Variable	Low	Med	High
Discrete one yr value	SavingsOne ($M)	$0.83	$1.09	$1.58
MW Need (Hi, Med, Lo)	MW Need (1 yr)	4	3	2
Avoided Cost	AvoidedCost	$207	$362	$790

Note that these avoided costs assume a one year deferral of the investment, and actual benefits per kW would likely vary, and potentially be zero if insufficient MW reductions are modeled to allow deferral.

2.1.4 DETERMINATION OF NEEDED LOAD REDUCTIONS

The load reduction used in the calculation of the deferral value should reflect the distribution planners' expectation of needed peak reductions. In some applications, annual load growth has been used as a proxy for the needed load reductions; in other studies, peak capacity deficiency has been used. For the intended use of locational values for targeted DER, we recommend an initial deferral value assuming a three year deferral driven by a peak load reduction equal to the cumulative three-year deficiency.

E3 has been working on locational deferral projects for over twenty years, and has observed that multi-year deferrals of at least two or three years, as opposed to single year deferrals, are generally viewed as necessary to warrant the extra effort required to implement a targeted program and reschedule a distribution project. The use of the three years allows the deferral values to reflect this reality, and allow the load reductions to reflect a combination of immediate first year deficiency need as well as load growth over the second and third years.

Related to the question of *how much* load reduction is required is the question of *when* that load reduction is required to be operational in order to achieve a distribution project deferral. In situations where the load reduction is uncertain, it may be necessary for the observed load reductions to take place before deferring a project. For long-lived DERs, that results in only a small financial impact to the utility as payments for DERs are made earlier than needed (only a financing cost of money loss). For short-lived measures like demand response, and especially demand response that pays annually for participation, the early implementation of measures before they are actually needed to avoid capacity could result in significantly increased costs for the program. For example, assume that targeted DR would pay $10,000 annually for peak load reduction. If the reduction is not needed until 2020, but the effort begins in 2017, then $30,000 in payments are made for years 2017-2019 that are not assisting the deferral of the 2020 project (other than providing some risk reduction).

We expect that the need for early load reduction will decrease as targeted implementation were to gain more experience so that distribution planners could have more certainty of the ability of the program to deliver load reductions on time. However, in the early years, we do expect that some early implementation will be necessary, and would be reasonable.

2.2 Determining DER measure coincidence with peak load hours

2.2.1 PEAK CAPACITY ALLOCATION FACTORS

To allow calculation of DER coincidence the peak load hours, the LNBA Tool calculates hourly allocation factors to represent the relative need for capacity reductions during the peak periods specific to each distribution area. The concept is based on the Peak Capacity Allocation Factor (PCAF) method first developed by PG&E in their 1993 General Rate Case that has since been used in many applications in California planning[3].

The peak hours could be defined in three ways:

[3] For example, PCAfs were used recently in a CPUC report quantifying distributed PV potential in California: http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

1. Specification of months and hours. E.g.: peak period is July and August hours between 4pm and 7pm on weekdays.
2. Specification of area peak threshold. The peak period would consist of all hours with forecasted demand above the specified threshold MW. The forecasted demand would be net of all existing and forecast naturally occurring generation (both behind the meter and in-front of the meter) located downstream from the planned distribution investment.
3. Statistical specification. The peak period would consist of all hours with demand within one standard deviation of the single hour maximum peak demand for the area. In other words, the area peak threshold is calculated by the LNBA Tool based on the variability of the area loads.

The relative importance of each hour is determined using weights assigned to each peak hour either 1) in proportion to their level above the threshold, or 2) on a uniform basis. Hours outside the peak period are assigned zero weight and zero value.

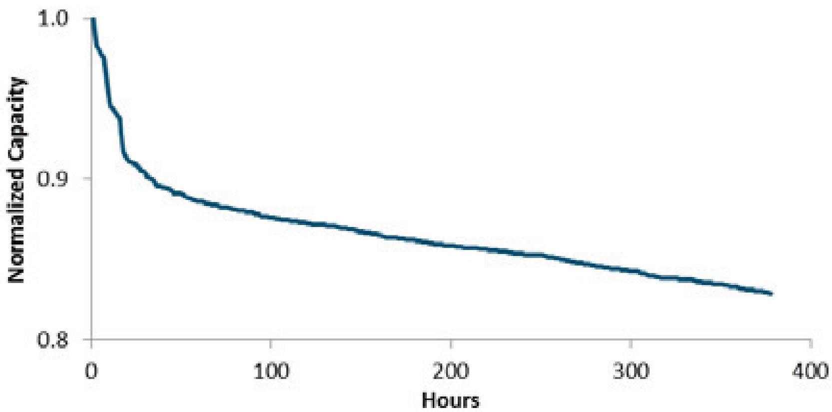
The formula for peak capacity allocation factors (PCAFs) using proportional weights is shown below.

$$PCAF[yr][hr] = \frac{Max(0, Load[yr][hr] - Thresh[yr])}{\sum_{hr=1}^{8760} Max(0, Load[yr][hr] - Thresh[yr])}$$

Where *Thresh[yr]* is the load in the threshold hour or the highest load outside of the peak period.

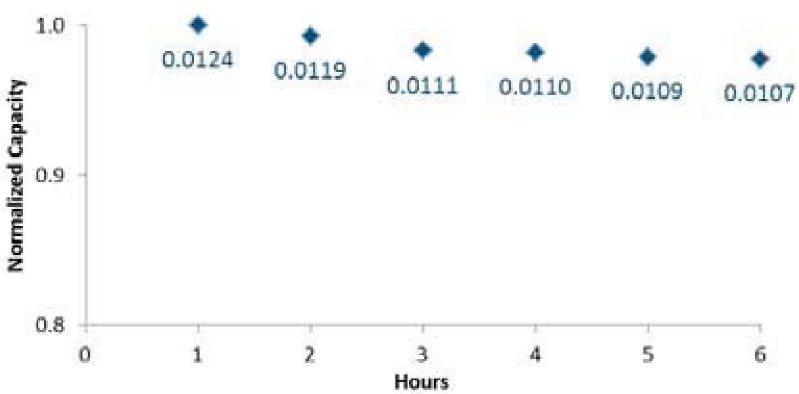
Once the PCAFs have been determined for each hour of the year, these are multiplied by the dependable output of each DER shape to determine the dependable MW contribution to peak load reductions. The following series of figures show an example of this process using the statistical peak period definition. One standard deviation from the top of the load duration curve above leaves the following hours with higher load than the threshold.

Figure 3. Example of PCAF calculation



This relatively flat load duration curve has more hours above the threshold than other peakier load duration curves – in this case, there are 378 hours. A PCAF is assigned to each one of these hours using the formula above. The following chart shows the PCAFs for the top 6 hours of the load duration curve as an example. The number below each plotted hour's normalized load represents the PCAF relative importance to peak load reductions. They are unit less, sum to one over the hours above the threshold, and can be thought of as the weights in a weighted average calculation of a particular resource's capacity contribution.

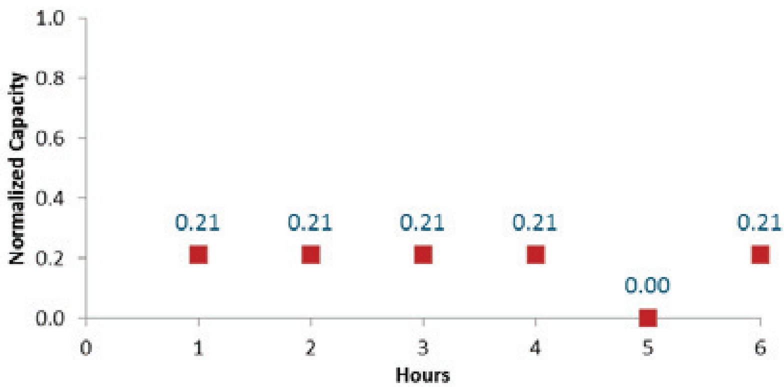
Figure 4. PCAFs for top 6 hours of load duration curve



2.2.2 COINCIDENT DEPENDABLE CAPACITY

The next step in determining a distributed resource's dependable capacity contribution to peak load reductions is to determine the coincidence of the resource's output with the highest load hours. Dependable capacity contribution is the load reduction that the utility would trust to use in planning for deferrals, and ways of calculating it are discussed in more detail in Section 2.3, *Determining the dependable output of a DER measure*. The figure below shows example hourly normalized dependable load reductions (DLR_h) for a portfolio of commercial air conditioning (AC) energy efficiency (EE) resources in the 6 highest load hours. A normalized capacity of 1 represents the maximum load reduction achievable over the previously installed AC technology. These represent the dependable output of the measure - what the utility can count on in each hour to reduce load.

Figure 5. Hourly dependable capacity factors for EE output during the 6 highest load hours



To calculate the dependable MW contribution of the EE measure, the following formula is used:

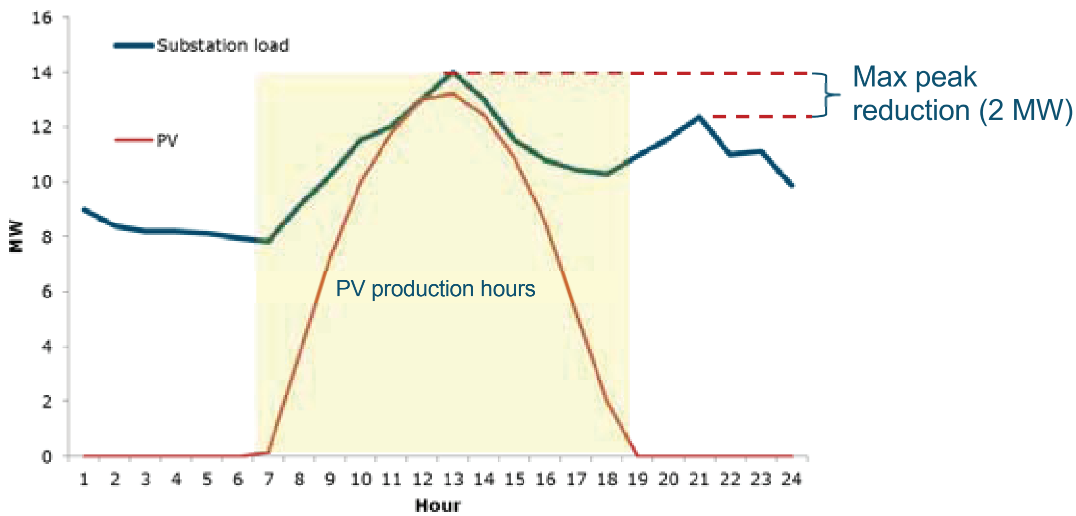
$$DepMW = \sum_{h \in (H|L_h \geq threshold)} DLR_h \times PCAF_h$$

The sum is performed over the hours in the total number of hours in the year (H) in which the load (L_h) is greater than the threshold (378 hours in the example). 20.5% of the EE measure's maximum capacity impact qualifies towards load reductions. Therefore, of the maximum capacity impact of a portfolio of new AC units of 1 MW, only 205 kW is counted towards deferring the distribution investment based on the combined effects of the distribution circuit load shape and the load shape of the DER. This produces a reasonable estimate of the dependable capacity or load reduction of the DER resource that can be used in planning and valuation models.

2.2.3 DYNAMIC NATURE OF PCAFS

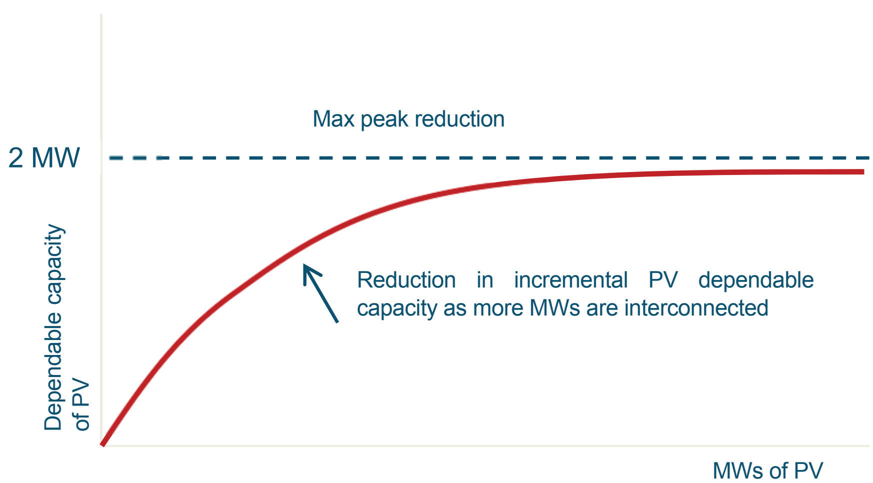
Note that as the load changes with load growth and DER implementation, the PCAFs will change. This is shown in the following example where the deferrable investment is at a substation. In this example PV is installed below the substation. The shape of the aggregate PV below the substation is shown below the substation load curve. As the level of PV increases, the daytime peak is reduced. However, there is a point where further increases in PV may reduce the daytime peak but will not reduce the peak load at the substation because of the evening peak is higher than the day time net peak.

Figure 6. The limit to peak load reductions



In this example, the effectiveness of standalone PV at reducing the peak diminishes as the peak is shifted away from the middle of the day, approaching an asymptote at the maximum peak load reduction (2 MW in the example). This is shown in the following figure.

Figure 7. Diminishing marginal dependable capacity of standalone PV



This effect is prominent with daytime peaking DER resources such as PV, however all DER measures have interactions with the load shape, and each other, that may result in diminishing capacity returns. DER resources can also complement each other, offering more capacity together than either one can alone. PCAFs must therefore be updated whenever the load shape, net of DER output, changes significantly. This is particularly true when calculating local distribution capacity benefits, because the DER measures added to reduce peak load may be a significant fraction of the total load.

Note: The complexities of dynamic PCAFs are important for a complete understanding of the interaction of DER and distribution needs. However, it remains unclear at the present whether such effects will be modeled in the Demo B projects and the associated LNBA tool.

2.2.4 REFLECTING THE IMPACT OF ALREADY INSTALLED DER ON THE PEAK HOUR RISK

The next section discusses in detail the ways to model the dependable output of DER. The greater the number of DER measures installed, the closer the dependable output is to the expected output, but also the higher the risk of variation for weather sensitive DER. These facts raise the question of whether the dependable output for DER should only be considered for incremental DER, or should also be considered in determining the impact of existing installed DER on the hourly peak period loads used to develop the PCAFs.

Net approach

The standard approach is to use area demands that are net of historical DER. We refer to this as the "net" approach. The net approach is appropriate when there is a relatively low amount of DER in an area, or that DER is consistent and predictable in its impact on the area. The net approach involves calculating the coincidence of the dependable capacity shape for a marginal DER addition with the net load shape (net of previously installed DER measures). Using this method, the risk of not meeting load reductions associated with previously added MWs of DER is not captured. At higher penetrations of weather-dependent DER in a local area, particularly one with not much geographic diversity, a single year's net load shape may not be enough data to base capital planning decisions on because the uncertainty around previously installed DERs will not be factored into them.

Gross Approach

The alternate approach is to use area loads that are reconstructed to reflect what they would have been without DER and then subtract out the dependable (not historical) amount of existing DER output and demand reduction. We refer to this as the "gross" method because it requires a reconstruction of total customer usage prior to reductions from DER. This method would incorporate the risk criterion (i.e. the percentile, or other risk metric) into the contribution of all DER towards peak load reductions. This option is better capable of reflecting the risk of the entire installed DER portfolio of not providing expected peak load reductions – a risk level that may be significant at high penetrations of weather-dependent DER in low geographic diversity regions.

The gross approach is the more conservative option, it is more appropriately applied across all geographic levels of the system from line segment up to system level since it incorporates changing amounts of geographic diversity, and the first approach is inconsistent since it only applies a risk derate to the marginal kW of DER and not to the existing installations. However, there will still be some geographic diversity effect captured in the first method that is reflected in the load shape of the DER resources.

The gross approach is also more data intensive, requiring knowledge of all existing DER installations down to the smallest geography considered in the model including their load shapes. This level of data is unlikely to be available system wide. At lower levels of DER penetration, the first approach using the net load shape will approximate the second most closely at lower DER penetration levels. As levels increase, the risk associated with the existing resources in delivering expected capacity reductions will also increase.

Whether gross load or net load is used in the analysis depends on the data availability on the particular part of the network being studied and the amount of weather sensitive DER already installed in that part of the network. *The method(s) that is(are) used for the Demo B projects are unclear at the time of this writing.* In either case, whether Net or Gross approaches are used, the objective of the analysis is to estimate the avoided distribution costs impact of incremental DERs in a particular location.

2.3 Determining the dependable output of a DER measure

As mentioned above, the ability for DER to defer a distribution investment depends upon the coincidence of the DER with the distribution area peak needs, as well as the dependability of those DER reductions. The prior section's discussion of PCAFs addressed the coincidence of DER. This section addresses the dependability of DER. Dependability of DER is typically a low impact issue when looking at system-wide DER implementation because of the large diversity offered by large numbers of installations. Expected DER output is generally sufficient for estimating system-wide impacts. However, at smaller local distribution areas, the installations of DER will be smaller in number and the "safety" of the joint output of large numbers of devices will diminish. Therefore, the dependability of DER is a more important factor for smaller local distribution areas. In addition, DER that are weather dependent (such as PV) will be subject to common “failure” modes as the weather could impact all units in an area simultaneously. Therefore, the dependability of weather sensitive DER (both future and existing) is important as the penetration of those DER in an area increases.

The dependable output of a DER measure varies by the acceptable risk level for an area. For example, a planning rule could be to accept a level of DER output that the DER measure is at or above more than 97% of the time during peak load hours. DER measure output can be derated to meet the defined planning criteria. The derate is determined by several factors:

1. Whether it can be reliably called or controlled during peak load hours,
2. what the outage rate of the measure looks like,
3. in the case of renewable generation, what is the uncertainty around the output,
4. the geographic diversity and number of installed measures, and
5. the impact of a circuit outage on the ability of the DER to perform.

These factors influence the measure impact/production shape and the derate to a greater or lesser extent. For example, energy efficiency is not ‘dispatched’, but is built into the infrastructure of the building or building appliances. However, energy efficiency measures tend to be installed in large numbers, reducing the uncertainty around its output and converging on a relatively low derate. Likewise, measure impact/production shapes should reflect the diversity of installing a portfolio of new systems across customers, capturing the effect of many systems contributing at the same time to load reductions. DR, on the other hand, must be controlled in the absence of a strong price signal. Estimating the derate factors comes from experience over time with installed measures. Assuming the outages reflected in the derate are uncorrelated with time of day or year, the derate can be uniformly applied to an hourly measure impact shape. This is the dependable measure output.

An alternative to calculating a weather-dependent DER derate directly (for example, in the case of PV), a dependable output shape can be determined. First, find the distribution of PV output in each hour and season. These can be formed from the aggregate output of all weather-dependent DER below the deferrable investment on the distribution system. From these distributions take the percentile corresponding to the planning rule appropriate for the area. For example, if 97% reliability is required, the model will take the 3rd percentile of each hourly and seasonal distribution. The result is a level of output from PV that in each hour of the year, PV would be expected to produce at or higher than for 97% of the time. This is the dependable PV measure output. The advantage of using this method is that for investments with very little geographic diversity in the region electrically downstream, the dependable MWs in each hour from weather dependent DER will be low because the shape without diversity benefit is more likely to be strongly affected by cloud cover etc. Conversely, investments with a lot of geographic diversity downstream will have relatively high dependable MWs in each hour because of the diversity benefit to the aggregate shape of the weather-dependent DER resource.

The dependable output of dispatchable resources depends on them being dispatched for local T&D capacity benefits. However, whether they are used for T&D deferral or not will depend on the value to the customer of T&D deferrals vs other value streams such as system capacity or ancillary services. The output of dispatchable DERs may be partially or fully derated if they are dispatched for another purpose. Only DER with contractual obligations to prioritize T&D functions will receive local T&D capacity benefits in the model.

2.3.1 MODELING OF DISPATCHABLE RESOURCES

The dependable output of a dispatchable resource is dependent on the dispatch used. These resources need to be dispatched for distribution benefits for dependable deferrals. If dispatched for system benefits, they may need to be significantly derated for distribution deferrals – particularly if the local distribution load shape is very different from the system load shape, or if storage is dispatched for other value streams such as ancillary services. Programs for an effective distribution deferral dispatch regime for DR and storage are beyond the scope of this framework. However, one method could include contracted utility control of storage during only high distribution load hours, and leaving the storage device to operate for highest value at all other times. Essentially a call option on the DER with a strike (trigger) set by distribution operations based on local reliability assessments.

When DERs are dispatched for distribution benefits the constraints on dispatch, and the uncertainty on load levels when the dispatch calls have to be made, factor into calculation of the DER dependable capacity contribution. For example, both storage and DR must be dispatched ahead of time based on forecasted loads. The forecast error determines the level of coincidence between storage and DR with the peak hours. There are further constraints to consider. For example, DR may only be called a certain number of times per year, and both storage and DR have limitations on the length of their discharge periods.

THE LNBA Tool will model the dispatch of DERs using perfect foresight under two different program options: first is a customer controlled dispatch against customer rates, with an optional utility call for local or system capacity benefits; second is a utility controlled dispatch against utility energy prices, capacity and T&D needs. These dispatch regimes will be subject to the technical constraints of the resources being modeled. Demand response will be dispatched assuming perfect forecasting, and capturing the effects of limits on annual calls, and length of discharge period. Perfect forecasting overestimates the effectiveness of dispatchable DER. However, it can be combined with a user inputted derate to account for that. The derate can be set by the utilities in future applications of the framework to approximate the effect of uncertainty. Dispatches for DERs will be done for a single year.

3 Avoided Costs from DERAC

The DERAC model will be replaced by an Avoided Cost Model (ACM) that is currently being updated. A draft ACM was made available to stakeholders on June 1, 2016, and final model is scheduled to be released in the beginning of July 2016. The following avoided cost components will be transferred from the ACM into the LNBA Tool to allow for DER resources to be evaluated with a full set of avoided cost values.

- Generation system capacity avoided cost
- System energy avoided cost, day ahead market, net of embedded CO_2 costs (not LMP values).
- Ancillary service costs (included as a percentage adder to energy prices)
- Energy losses avoided costs (for delivery to secondary voltage)
- CO_2 costs (embedded in energy market prices, but separated out for reporting purposes)
- RPS adder costs (cost of the above market price of renewables multiplied by the percentage of retail sales that must be met by RPS qualified resources).

The costs are generated hourly, and forecasted out for 30 years. The hourly variation in avoided costs are based on 2015 historical energy prices and forecast changes in market clearing prices due to increased renewable generation serving the state. Historical energy price shapes could be updated to account for the increase in renewables and in particular as a result of the increase in solar penetration.

4 Avoided costs outside of DERAC

4.1 Flexible RA

The LNBA team has identified two methods for including flexible RA in the model. A preferred method has not yet been selected. One option is to calculate the flexible RA impact of a DER by taking its output change over the three-hour period starting in the hour indicated in the table below (from the 2016 Flexible Capacity Needs Assessment (FCNA)[4]) for November (the month with the highest 3 hr ramp):

Table 5: 2016 Forecasted Hour in Which Monthly Maximum 3-Hour Net load Ramp Began

Month	Starting Hour	Month	Starting Hour
Jan	14	Jul	12
Feb	15	Aug	12
Mar	16	Sep	14
Apr	16	Oct	15
May	16	Nov	14
Jun	15	Dec	14

This uses the expected DER profile. Adjustments for dependability (see prior section) would not be required as the flexible RA impacts accrue at the system, not the local distribution area level.

A second alternative is a user input factor that translates MW of DER into a MW increase/decrease of flexible RA requirement. This is easily done for solar, wind and EE, since these are explicitly represented

4 https://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf

in the CAISO hourly data that is used to create a forecast of net load to determine the flexible RA requirement[5].

[5] https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityNeedsTechnicalStudyProcess.aspx

5 Process and implementation

5.1 System disaggregation level

The methodology above can be applied to all levels of the electricity grid from bulk system down to circuit. Tailoring the framework to each level requires data specific to the loads and DER impacts experienced at that level. Applying the framework to a distribution planning area, for example, will potentially include several different avoidable T&D investments. DER located at the end of a feeder line could potentially have local line segment voltage impacts, substation equipment deferral, and sub-transmission deferral, in addition to avoided costs at the system level. System level non-transmission related avoided costs will be calculated using the DERAC. However, the remaining T&D avoided cost components are calculated using the above framework using the level of system disaggregation appropriate to each identified deferrable system upgrade. Below are presented examples of the level of system disaggregation and the data needs for each of the avoided cost categories identified in the introduction of this document.

5.2 Data requirements

The data requirements for evaluating project deferrals will vary depending on the level of granularity of the analysis. Evaluation of loads and planned T&D investments require the following:

- Information about load growth related T&D investments planned for the future, including timing, costs, and development lead times.
- Hourly loads by planning area. Depending on the granularity of the analysis, loads will be needed for the system downstream of each planned T&D investment. (loads should reflect any expected system reconfigurations). The corresponding load growth, including any potential changes in shape expected over time if available, is also needed.

Characterization of the DER being evaluated for deferral varies by technology type. The following information is required.

- Dispatch constraints for dispatchable DER. The notification time and discharge period are required for DR and storage. Additionally, the maximum number of calls on DR is needed.

The level of system disaggregation needed is dependent on the specific avoidable investments identified. An example is shown below for the first category – avoided sub-transmission, substation and feeder capital and operating expenses.

5.2.1 EXAMPLE DATA NEEDS FOR AVOIDED SUB-TRANSMISSION, SUBSTATION AND FEEDER CAPITAL AND OPERATING EXPENSES

Example: a new transformer bank at a substation identified as necessary to meet future projected load growth.

Grid disaggregation level: the substation and all loads and DER electrically downstream of the substation.

Data required:

- Aggregated load data from electrically downstream of the substation

- Aggregated DER impact shapes from all non-dispatchable DERs installed downstream of the substation (to allow determination of the weather sensitivity and aggregate dependability of both existing and incremental DER in the area). Hourly output shapes for potential incremental non-dispatchable DER that are weather matched to the load data. For EE these include end use specific impact shapes. For PV, as much data as available from all geographically diverse PV locations downstream of the project is important to develop dependable capacity contributions. Capturing the diversity effect becomes more important as the geographic area downstream of a project becomes larger, such as at sub-transmission level.

- Aggregated dispatchable DER technologies and the tariffs/programs used to operate them

5.3 Incorporation into Utility Planning Processes

The LNBA Tool is designed to satisfy the requirements of Demo B Modeling, as well as provide a learning platform for the utilities and stakeholders to become experienced with the LNBA needs and opportunities. The LNBA Tool is a "research tool" and not a "production grade" tool that could be integrated efficiently into utility planning processes.

While developing the specifications for the LNBA Tool, the team has considered some of the issues that could arise with the implementation of the methodology into the utility planning processes. While the list is not extensive at this point, the issues would include the following:

- **Project identification and lead times.** Projects will need to be identified early to allow sufficient time for DER implementation. The development lead time on T&D investments determines the point at which demonstrable load reductions must be made to defer an investment. This may correspond to the time at which equipment needs to be procured to complete construction of a T&D facility on time. The demonstration criteria may include either all required load reductions to be demonstrated, or some fraction of load reductions. Project lead time may decrease, or the demonstration criteria may change over time as the utilities gains more experience with DER programs.

- **Project Cost Estimates.** Project costs will be necessarily vague and generic for projects planned for many years in the future. Deferral plans should be updated every year to reflect more accurate cost estimates as project installation dates become closer and specific project plans are developed.